UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

NTL No. 99-N04 Effective Date: March 5, 1999

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES
IN THE OUTER CONTINENTAL SHELF

Revised Guidelines for Royalty Relief Under 30 CFR Part 203

This NTL supersedes NTL 98-17N and amends the guidelines for applying for royalty relief. As we stated in earlier NTLs on royalty relief, we expect to periodically update these guidelines to reflect our experience in processing applications.

Under 30 CFR Part 203, certain lessees may apply to MMS for a suspension of royalty payments or a reduced royalty rate by submitting a complete application. We describe the specific data elements, parameters, reports and computer model or spreadsheets in a complete application in two separate Appendices to this NTL. These guidelines are Appendix I: GUIDELINES FOR THE APPLICATION, REVIEW, APPROVAL, AND ADMINISTRATION OF THE DEEP WATER ROYALTY RELIEF PROGRAM and Appendix II: GUIDELINES FOR THE APPLICATION, REVIEW, APPROVAL, AND ADMINISTRATION OF ROYALTY RELIEF FOR END-OF-LIFE LEASES. They also explain the procedures we will follow for evaluating applications and implementing royalty relief.

We make seven changes in the Appendices from the previous versions of these guidelines.

(1) We may grant a departure from a specific provision in the guidelines when an applicant makes an explicit and compelling request prior to or at time of application. See Section A. in both Appendix I and Appendix II.
(2) We may interrupt our evaluation if an applicant drills additional wells after filing an application but before we have made a determination. See Sections F. and G. in Appendix I.
(3) We accept RSVP results that contain up to 20 percent loss-limited trials, instead of up to 10 percent as specified previously. See Section H. in Appendix I.
(4) We update the price assumptions used to evaluate future applications. See paragraph b. in the Economic Viability and Relief Justification Report of Appendix I.
(5) We now require that applicants submit the expected maximum shut-in pressure at the wellhead. See paragraph g in the Geological and Geophysical Report of Appendix I.
(6) We clarify the definition of production. See Section C. in Appendix II.
(7) We add an example of how to calculate the weighted average price increase that would cause us to suspend royalty relief. See Section E. in Appendix II.

We advise that you carefully review a copy of the appropriate guidelines if you intend to request royalty relief. They will help you structure your application to expedite our evaluation. The most current version of the guidelines display a date of March 1999.

You may request a copy of the guidelines from your regional office. They, along with the computer model or spreadsheet that you will need to prepare an application, are also available on the MMS website at http://www.mms.gov.

We believe our deep water and end-of-life programs cover the large majority of cases where royalty relief appropriately balances lessee and public interest. However, we recognize that royalty relief may serve the statutory purposes in exceptional situations that do not conform to our formal programs. As summarized in 30 CFR 203.1 (1998), these statutory purposes include promoting increased production in any lease areas, or promoting development and production of marginal resources in the Central and Western Gulf of Mexico. Characteristics we look for in these exceptional situations include, but are not necessarily limited to, two or more of the following.

(1) The lease has produced for a substantial period and lessee can recover significant additional resources.
(2) Valuable facilities exist on the lease that are unlikely to be used by a successor lessee (e.g., a platform or pipeline that would be removed upon lease relinquishment).
(3) There is a substantial risk that the resources would never be recovered otherwise (e.g., re-leasing by MMS in future lease sales is unlikely).
(4) The lessee made major efforts to reduce lease operating costs too recently to utilize the formal program for royalty relief (e.g., recent significant change in operations).
(5) Circumstances beyond lessee control preclude reliance on one of the existing royalty relief programs.
(6) Formal relief programs provide inadequate encouragement to increase production or development but other workable forms that provide the public with a fair market value do so (e.g., variable rather than fixed reductions in royalty rates).

If you believe your situation is exceptional as discussed above, you should present the data and arguments for allowing you to seek royalty relief outside our formal programs to the MMS Associate Director for Offshore Minerals Management. Particularly in this period of record low oil prices, we want to assure that any situation that may merit royalty relief be given consideration to apply.

If you have any questions on this NTL, you may contact Marshall Rose (703) 787-1538.

Paperwork Reduction Act of 1995 Statement: Any collection of information that we mention in this NTL and its guidelines provides clarification, description, or interpretation of requirements contained in 30 CFR Part 203. The Office of Management and Budget has approved our collection of information required by these regulations and assigned OMB Control Number 1010-0071. These guidelines do not impose additional information collection requirements that would be subject to the Paperwork Reduction Act of 1995.

Carolita U. Kallaur

Dated: March 5, 1999

Associate Director for
Offshore Minerals Management

UNITED STATES DEPARTMENT OF THE INTERIOR

MINERALS MANAGEMENT SERVICE

Appendix I to NTL No. 99-N04

GUIDELINES FOR THE APPLICATION, REVIEW, APPROVAL, AND ADMINISTRATION OF THE DEEP WATER ROYALTY RELIEF PROGRAM

March 1999

TABLE OF CONTENTS

REPORTS

ATTACHMENTS

Recovery of Costs

According to Federal policy and statute, we charge you a fee for applying for royalty suspension volumes to recover our cost of processing your applications. The Administrative Procedures Act (31 U.S.C. 9701) and Office of Management and Budget Circular A-25 require that we recover our costs when we provide services that confer special benefits or privileges to identifiable non-Federal recipients. Processing of applications for royalty relief clearly falls within this mandate.

Furthermore, our collection of such fees is specifically authorized by the Omnibus Appropriations Bill (PL. 104-134, 110 Stat. 13221, April 26, 1996). The statute provides: "That beginning in fiscal year 1996 and thereafter, fees for the royalty rate relief applications shall be established (and revised as needed) in Notices to Lessees, ... for the costs of administering the royalty rate relief authorized by 43 U.S.C. 1337 (a) (3)."

We may issue a notice to lessees and operators (NTL), updating NTL 98-5N, to provide more detailed information on the royalty relief application fees and when and how you must make payments. We will revise the NTL periodically to reflect our cost experience and to provide other information necessary for the administration of this program.

OVERVIEW OF GUIDELINES
FOR DEEP WATER ROYALTY RELIEF APPLICATIONS UNDER 30 CFR PART 203

We issued final regulations (30 CFR Part 203) in January 1998 to implement the Outer Continental Shelf Deep Water Royalty Relief Act (Public Law 104-58 (DWRRA)). This Act clarified and expanded the Secretary of the Interior's authority in 43 U.S.C. 1337(a)(3) to reduce royalty rates on existing leases in order to promote development, increase production, and encourage production of marginal resources on producing or nonproducing leases. This authority applies to oil and gas leases on the Federal Outer Continental Shelf (OCS) in water at least 200 meters deep in the Gulf of Mexico west of 87 degrees, 30 minutes west longitude that were in existence before November 28, 1995. Authorized lease(s) qualify for a royalty suspension volume if we determine the field from which it would produce needs royalty relief to be economic.

Affected lessees may apply to the Minerals Management Service (MMS) for suspension of royalty payments by submitting the information specified under these final regulations. These supplementary guidelines detail the format for submitting the necessary information and the procedures and rationale we follow for evaluating applications.

We advise that you review a copy of these guidelines if you intend to request deep water royalty relief. These guidelines do not add any requirements to the regulations but they will help you structure your application so as to expedite our evaluation. Be sure to use the most current version of these guidelines as we will periodically update them to reflect our experience in processing applications.

Part of your submission requires you to use a computer model which you may obtain from our Regional Supervisor for Production and Development for the Gulf of Mexico OCS Region. The NTL, the computer model and its documentation, and these guidelines are also available on the MMS website at http://www.mms.gov.

Any collection of information that we mention in these guidelines provides clarification, description, or interpretation of requirements contained in 30 CFR part 203. The Office of Management and Budget has approved our collection of information required by these regulations and assigned OMB Control Number 1010-0071. These guidelines do not impose additional information collection requirements that would be subject to the Paperwork Reduction Act of 1995.

Carolita U. Kallaur

Dated: March 5, 1999

Carolita U.Kallaur
Associate Director for

Offshore Minerals Management

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Effective Date: March 5, 1999

Guidelines for the Application, Review, Approval, and Administration of the Deep Water Royalty Relief Program

A. Introduction

These guidelines interpret regulations (30 CFR Part 203, Subpart B) which establish the terms and conditions for granting royalty suspension volumes under the Deep Water Royalty Relief Act (DWRRA). They apply to Outer Continental Shelf (OCS) oil and gas leases in water depths of 200 meters or more in the Central and Western Gulf of Mexico (GOM) that were in existence before November 28, 1995. Other guidelines interpret terms for reducing royalty rates under the Outer Continental Shelf Lands Act (OCSLA).

As with the rule, we've written these guidelines in the "plain English" or conversational style. We (Minerals Management Service) give you (applicants, lessees, operators) directions on what to include in your application and what to do after we process it. Also, we explain how we will process your application and in some cases why we do it that way. Each section of these guidelines refers to the corresponding section in the regulations.

Guidelines are not strict rules like regulations, so we may deviate from individual elements of them if an applicant makes a convincing argument to do so. We will consider requests for deviation from the guidelines only when an applicant provides compelling reasons for deviating from a provision before submitting a royalty relief application.

The authority for the regulations and guidelines is as follows: 30 U.S.C. 181 et seq.; 30 U.S.C. 351 et seq.; 30 U.S.C. 1701 et seq.; 31 U.S.C. 9701; 43 U.S.C. 1301, et seq.; 43 U.S.C. 1331 et seq.; and 43 U.S.C. 1801 et seq.

B. Objectives of Deep Water Royalty Relief (DWRR) (supplements 30 CFR 203.1(c))

We may grant royalty suspensions in order to promote development, increase production, or encourage production of marginal resources on producing or non-producing deep water leases. However, our authority to do this is restricted in three important ways. One, it applies only to the Western and Central Planning Areas of the GOM and the portion of the Eastern Planning Area of the GOM encompassing whole blocks lying west of 87 degrees, 30 minutes west longitude. Two, it applies only to deep water leases in existence before November 28, 1995, that are on fields that did not produce before that date or whose lessees propose projects to significantly expand production. Three, we may suspend royalties only for volumes of production needed to make the field or project economic, subject to minimum volumes for fields that did not produce before November 28, 1995.

We implement these royalty relief provisions in conjunction with our stewardship responsibilities for sound management of public lands. This includes conservation of resources, obtaining a fair return to the public on OCS resources and ensuring that all OCS development is safe and consistent with sound environmental standards.

C. Relation of DWRR to Other Types of Royalty Relief (supplements 30 CFR 203.2)

We offer three types of royalty relief as described in the following table. DWRR is represented by rows 2 and 3. Row 1 represents relief available under the original OCSLA. Attachment A summarizes the main features of the various kinds of royalty relief.

IF YOU HAVE A LEASE...	AND IF YOU ...	THEN WE MAY GRANT YOU ...
that generates earnings which can't sustain production (**End-of-Life lease**),	seek to increase production by continuing to operate the lease beyond the point it is economic at the existing royalty rate,	a reduced royalty rate on current production flows along with a higher royalty rate on some additional production flows.[1]
in designated areas of the deep water GOM, acquired in a lease sale held before November 28, 1995, and you	are producing and seek to increase ultimate recovery of resources from the field with a substantial investment (e.g.,	a royalty suspension for an increment to production large enough to make the project economic.

propose activity in a DOCD or supplement to significantly expand production,	platform, multiple wells, subsea template) (**Expansion project**),	
in designated areas of the deep water GOM, acquired in a lease sale held before November 28, 1995 (**pre-Act lease**),	are on a field from which no current pre-Act lease produced, other than test production, before November 28, 1995 (**Authorized field**),	a royalty suspension for a minimum production volume plus any additional volume needed to make the field economic.

[1]See the separate End-of-Life Lease Guidelines available from your regional MMS office for further explanation.

D. Basis for Granting DWRR Relief (supplements Part V. Administrative Matters of the DWRR Rule and 30 CFR 203.60, 63-64, 72)

Section 302(C) of the DWRRA states that an application may be made on the basis of an individual lease or unit. The term, "unit," isn't defined in the Act. The most fundamental issue we face in implementing the DWRRA is should we base royalty relief on single leases or on some geologic or economic unit, such as a field?

Consistency with New Leases: We faced the same issue in the rule for Eligible leases (i.e., issued in sales after November 28, 1995). As we explain in detail in the preambles for our rules implementing Sections 302 and 304 of the DWRRA, we believe the field basis for relief is consistent with Congressional intent.

Under 30 CFR 260.110, an Eligible lease receives a suspension volume automatically, without demonstrating a need for the suspension to assure economic viability. These automatic volumes are established for the fields to which we subsequently assign the Eligible lease. We structured the rule and guidelines to apply royalty suspension provisions for pre-Act leases consistently with royalty suspension provisions for Eligible leases. Accordingly, we follow three principles.

First, we don't grant a royalty suspension volume to a field where any current lease produced before November 28, 1995, except in the case where you undertake a project to significantly expand production on your field. Since those leases which undertook the initial production from the field (and can be said to have taken the most risk) are not eligible for a royalty suspension volume under the DWRRA, neither should the lessees of leases on that producing field that begin production after the DWRRA's enactment. Under these circumstances, Congress certainly recognized that it isn't necessary to encourage production.

Second, we grant only one royalty suspension volume per Authorized field (i.e., a field not producing before November 28, 1995). We believe the Congress added "or unit" to Section 302 of the DWRRA to allow us to evaluate multi-lease fields. We don't compel unitization of fields applying for royalty relief. But, we expect leases in multi-lease fields that are not unitized to submit a joint application, as discussed in section F and we allocate a suspension volume as explained in section K.

Third, we may grant you a separate royalty suspension volume for each field that includes your lease and qualifies under section H. We may also give you relief for a project that will significantly expand production, even if we already granted a royalty suspension volume to the field that encompasses that project.

Field Designation: Our definition of a field is based on geology and for the purpose of royalty relief is found in 30 CFR 203.0. We directly notify all affected lessees when we establish or redefine a field and issue the OCS Operations Field Names Master List (FNML), which lists all the tracts in each field on the GOM OCS each quarter, with monthly updates. Our Field Naming Handbook explains how we decide what constitutes a field. It identifies six major check points we use for assigning leases to fields and gives 12 examples of geologic structures in the GOM and the associated field designations. We make this Handbook available via INTERNET on the GOM Region's website.

We assign leases to a field when a well on the lease qualifies as capable of producing in paying quantities under the regulations at 30 CFR 250, Subpart A. If a well doesn't qualify under the rule, we assign the lease to a field when hydrocarbons are first produced from the lease or the lease is allocated production under an approved unit agreement. We may also include other leases that, in our judgment, are part of your field when we evaluate your application.

Because we continually update field definitions for new leases, data, and qualifying wells, we recommend that you confirm the most current lease make-up of the field before filing an application. That step will preclude delays as described below in processing an application that doesn't conform to our current definition of your field.

We recognize that you may occasionally disagree with the determination that your lease is part of a particular field. To minimize disagreements, we use an informal process to consult with you when establishing and revising field designations. Our regional office will notify you of a tentative field decision that affects your lease and offer you the opportunity for an informal review and consultation before finalizing your field designation. If you are still dissatisfied, you may appeal the final regional designation to the Director of MMS in accordance with the procedures in section M.

Application Criteria: The regulations identify four basic conditions for your lease before we will examine your application to suspend royalty payments on new production. Your OCS lease or unit must :

1. have been issued as a result of a lease sale held before November 28, 1995;
2. be in the GOM west of 87 degrees, 30 minutes west longitude;
3. be in a water depth of at least 200 meters; and
4. have been assigned to a field.

The deepest water depth on any lease in a MMS designated field establishes the water depth for that field. The water depth of a lease is governed by the "Royalty Suspension Areas" maps which we publish before lease sales for areas where the deep water royalty relief program applies. We base these maps on bathymetric data from the National Oceanic and Atmospheric Administration.

For purposes of drawing the map, if the water depth crosses a block, we include that block in the deeper water category. We will use the version of that map that is in effect at the time the royalty suspension application is submitted to determine the water depth of your field.

E. Nonbinding Assessments (supplements 30 CFR 203.61)

You may request a nonbinding assessment of whether your nonproducing, Authorized field would qualify for royalty relief before submitting the first complete application on a field. We offer this option to help those who seek an early indication about the chances for royalty relief on a marginal prospect.

We expect this option to be useful where you are reluctant to spend funds on reducing uncertainties about the commerciality of a field without an external opinion on its chances for royalty relief. This assessment also could shorten the time we need to evaluate your final application by identifying issues that otherwise would have led us to toll the clock to obtain an explanation or additional information. Finally, it may be useful for fields where you are not willing to risk having to meet the qualification requirements for a redetermination should we reject your complete application for relief.

Our assessment at this preliminary stage isn't binding for two reasons. One, further appraisal and planning can substantially change the approach, data, and assumptions from those we used for the early assessment. In contrast, your complete application for a binding relief determination presents the proposal upon which you agree to be bound as a condition for receiving the royalty relief we determine that you need. Two, we base our nonbinding assessment on the premise that the expected values of the data you provide will be confirmed by the additional appraisal and planning you complete before filing a complete application. Should your appraisal and planning fail to exclude other possibilities, our actual relief determination would have to be based on different input assumptions. If you wish a binding commitment to royalty relief, you need to submit a complete application as described in section F.

We don't require a complete application for the nonbinding assessment. However, we feel we can give you a reliable indication about your prospect's chances for relief only if you give us virtually equivalent details. A draft application containing preliminary estimates for all the data elements in the Administrative, Geological & Geophysical (G&G), Engineering, Production, Cost, and Economic Viability Reports is essential to insure that we are assessing the same prospect that you envision. To fully describe expectations for the prospect, you should submit a draft application consisting of all parts of the six reports, discussed in separate sections at the end of these guidelines. For a draft application, you need not include the certifications by an officer in your company and by an independent CPA firm as specified in 30 CFR 203.81 (b), (c), and (d) or in paragraph k of the Cost Report section.

We develop our nonbinding assessment of your field's royalty relief prospects presuming that your additional appraisal work would acquire data essential both to making a determination on royalty relief and a decision on development. Therefore, the regulation says your draft application for a nonbinding assessment must be accompanied by an appraisal plan that proposes to drill one or more additional wells should we render a favorable nonbinding assessment. Further, you need to identify appraisal and delineation expenses planned before submission of the complete application so we may consider them as sunk costs for purposes of our nonbinding assessment.

We fully expect that the uncertainty in the various estimates you present will be greater than would be the case in a complete application. However, all parts of an application contribute to a common view of the prospect. A fee, prescribed in a separate NTL, must accompany your draft application to cover our cost of developing a full assessment that dependably forecasts whether your prospect can expect to qualify for royalty relief. This fee is less than that for a complete application because we don’t do a completeness review as part of our assessment. While any final applications we may be evaluating will take priority, we intend to complete our nonbinding assessments as quickly as possible.

Once we provide a nonbinding assessment, the regulation specifies that you must wait at least 90 days before submitting a final application on the field. This is the case because we feel that 90 days is the minimum time you should need to conduct the additional appraisal and planning required to review and finalize a complete application.

F. Applications (supplements 30 CFR 203.62-63, 81, 83 & 85-89)

To apply for royalty relief, you need to file a complete application with the MMS Regional Director, Gulf of Mexico Regional Office, 1201 Elmwood Park Blvd., New Orleans, LA. 70123-2394. Applications may be for either:

1. An Authorized field which includes your pre-Act lease or unit; or

2. A project on your pre-Act lease or unit proposing development in a DOCD or supplemental DOCD approved after November 28, 1995, that will expand production significantly. Because DOCD's don’t require an estimate of production, we define significant expansion of production as any project that involves a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, or multiple well projects).

Content: You should finish all well appraisal work before you apply for royalty relief. A complete application includes the original and two copies (one copy for digital information) of:

1) Administrative Information Report;
2) G&G Report;
3) Engineering Report;
4) Production Report;
5) Cost Report; and
6) DWRR Economic Viability & Relief Justification Report.

You can find details on the format and content of these reports in the Report Section later in these guidelines. A short form application, as mentioned in section K, case 3, includes only report 1) above. You owe a fee with each application you submit. A complete application for an Expansion project also needs to reference an approved DOCD or supplemental DOCD.

Consulting and Certification: We will answer certain technical questions about your prospective application before we receive it and your processing fee. Such technical questions include: what is expected in the backup reports, how the RSVP model works, what needs to be in a complete application, and what the currently prescribed economic inputs are for the RSVP model.

The regulation says you or your authorized representative must certify that all information submitted in the application is accurate, complete, and conforms to the format and detail specified in these guidelines. Your application also needs to be accompanied by a report prepared by an independent CPA expressing an opinion on the accuracy of the historical financial information presented and on whether it conforms to the presentation format specified in these guidelines. You should identify an individual with the CPA firm who is knowledgeable about the project and authorized to answer questions on it, and make him or her available to respond to questions we may have on the historical information. We may also need to review your records which support the historical financial information in the application.

Multi-lease Fields: You should submit information about resources on all leases in the field. Also, you should either plan joint development or jointly design the application and make sure you meet the performance conditions for retaining approved relief. We’ve established the following joint application procedures.

1. We will accept only one joint application for all leases that are part of a field, as defined by the Regional Director, on the date of application, except as provided for in subparagraph 3. below. Our Regional Director for the GOM Region, maintains a list of all leases assigned to each field we’ve established.

2. You may submit separately to us proprietary G&G data that is a necessary part of the joint application, if you don’t want to share that data with other lessees on the field. Your application isn’t complete until we receive all the information stipulated in the rule for each lease on the field. In explaining our

assumptions and reasoning behind our determinations, we won't disclose proprietary data.

3. We will waive the joint application requirement if you show good cause for the waiver. You should fully explain this good cause and demonstrate that a good faith effort was made to obtain the participation of all lessees in the field. A lease that is assigned to the field on the date of application but that isn't included in the application, because its lessee(s) fails or refuses to participate, won't share royalty relief for the field that is the subject of the application. We will include an estimate of the non-participating lease's portion of field resources and costs in our economic evaluation of your field.

4. You or your successors may submit only one complete application for royalty relief during the life of the field, except in the following situations. You may submit another application if: a) you are eligible to apply for a redetermination under section I, b) you apply for royalty relief for an Expansion project, or c) you retract an application before we deem it complete.

G. Review (supplements 30 CFR 203.65-66)

We may take up to 20 working days after receiving your application to determine whether it's complete. If the application is complete, we will notify you and initiate the evaluation process. If the application is incomplete, we explain to you what the application needs to become complete.

If we propose to revise the make-up of your field after you file an application, we will not delay our completeness review. But, we will advise you that the field we intend to evaluate may differ from the one you described in your application. You may continue to contest this new field definition under the appeal process described in section M.

In situations where we modify your field during evaluation, we may notify you that we need more information to complete our evaluation. If our regional office does finalize a change in your field make-up, we will ask you to agree to toll the evaluation clock until you can modify your application to be consistent with the new field. If you decline to modify your application after our completeness letter notified you that we need more information, we will reject your request for royalty relief due to a lack of the required data on the entire field.

The DWRRA provides that if we don’t make the required determination 180 days after we deem your application complete (120 days in the case of a redetermination), we may extend the time period for making the determination or redetermination for 30 days, or for longer than 30 days if you agree. If we don’t complete the determination in the prescribed time period, together with any extension thereof, you get the minimum royalty suspension volume for the field, as specified in section K below (except when you retract your application). In the case of an Expansion project, the DWRRA specifies that we will collect no royalty on the new production for a period of one year following the start of such production, if we fail to make a determination on time.

The 180/120-day time period won’t begin until we determine and so notify you that your application is complete. Notwithstanding this notification, if during the evaluation period, we find that data in the application is missing, unclear, inconclusive, or otherwise cannot be relied on, we will request new data or information needed to make the application reliable and accurate. We request that you agree to our tolling the 180/120-day time period from the time we make our request until you provide us the needed information. When you supply the needed information, we will restart the time period with the same number of days remaining for our determination as when the time was tolled. If, within 30 days after our request, you’ve not agreed to toll the evaluation clock or answered our questions, we will proceed to evaluate what we believe is the most logical development and production configuration for your field.

You should notify us immediately if you begin drilling a well during the 180-day evaluation period. If you expect to complete the drilling operation within this period, we will ask that you agree to toll the clock so the new well information can be incorporated into our evaluation. We would toll the evaluation clock from the beginning of drilling operations at least until we receive the new information. If necessary, we would extend tolling for a specified period to provide time to complete our evaluation of the new information within the legal time limit. If you do not agree to tolling and to modify your application, we may reject your relief request because the accelerated drilling program is not consistent with your application or because your application lacks required data.

If we determine that we need to audit sunk costs in order to evaluate your application, we request the 180/120-day evaluation period be tolled from the time you receive our notice until you provide the records necessary to conduct our audit. See section L for the procedures of how this audit determination will be made.

H. Economic Evaluation Procedures (supplements 30 CFR 203.67-68)

Economic Measure: Over the years we've studied various measures to forecast whether or not a project might be economic. We've chosen to use net present value (NPV) in these types of assessments because we believe it best meets the characteristics needed to make proper decisions. Specifically, NPV analysis is an appropriate measure of profit, reflects the time value of money, can include quantitative elements of risk, indicates directly whether profit exceeds some minimum level, and can be used to compare and rank opportunities. Further, NPV analysis avoids the analytical problems found with other measures. For instance, rate of return analysis has iteration requirements, can have multiple solutions, and can give ambiguous rankings for projects.

When the NPV is equal to zero, an investment yields a rate of return equal to the chosen discount rate. If the NPV is less than zero, the investment earns a rate of return below the discount rate and is uneconomic. If the NPV is more than zero, the investment earns a larger rate of return and is economic. Therefore, in keeping with standard practice, we chose anticipated NPV as the decision parameter to be used in the determinations discussed below. We considered the use of a lower NPV criteria since a value only slightly less than zero could result in a large volume of relief. However, we dropped this idea due to the difficulty of justifying any such value.

Three Tests: We subject applications for DWRR to up to three discounted cash flow (DCF) analyses. All three analyses will use the same price and discount rate assumptions.

(1) *Viability Test*. We determine whether any royalty suspension volume can make your development and attendant new production economic. For this test the DCF is calculated under assumptions most favorable for finding a positive NPV. Proposals that don't predict a positive NPV when no royalties are ever collected from the field and when no costs before the date of the application are counted are either hopeless or exclude vital information.

You initially carry out this DCF analysis as part of the complete application using the Royalty Suspension Viability Program (RSVP v2.1) model that we provide. See Attachment D. In this analysis, we expect you to propose the system you intend to install if we approve royalty relief. Also, we expect you to define scenarios that fairly reflect the range of your uncertainty about the appropriate development scale for your field.

Subsequently, we review and verify your analysis to confirm this determination. The system you propose is presumed to be the most economic under the conditions used for this test. Our review focuses on confirming that you've included appropriate costs and identified adequate resources to predict profits with the proposed system when neither royalties nor sunk costs are included in the DCF.

We don't allow certain types of costs because they are not directly related to your production from your field. Paragraph G of the Cost Report section lists costs we consider ineligible. One of those items is costs for exploration activities, which we distinguish from delineation by the fact that they are not associated with a source of revenue or benefit to the field. RSVP v2.1 includes a feature to adjust for an ineligible element in well costs. When you propose drilling into previously un-penetrated reservoirs, the cost for that well and completion is included in the analysis only when that reservoir is sampled as not being dry. Under this treatment, the non-dry probability simulates the likelihood that you will drill the reservoir. We presume you would only do so into a productive reservoir. If the reservoir is to be penetrated by a well that goes through other reservoirs, a proportionate share of the well costs for non-dry reservoirs are counted. The documentation for RSVP v2.1 more fully explains how this and other features of the model work.

In those instances where no amount of royalty suspension volume would make your field economic, we deny your application for royalty relief.

(2) *Profitability Test*. We determine if development of your field or if subsequent new production from your field is economic while paying lease royalties. As we are obliged to evaluate the most economic system for developing your field, we invite you to identify alternative systems that you considered and why you believe those are less economic than the one you propose. We evaluate whether the system you propose, or a logical alternative, is most economic should full royalties have to be paid. If we determine that the development of the field would be economic without relief, we deny your application.

Besides royalties, sunk costs are central to this determination, so it is critical that we fully explain how we intend to consider them. Insofar as the overall goal of royalty relief is to promote the development of marginal fields, economic theory suggests that only costs that are relevant to the development decision of the operator need to be considered. Sunk costs don’t affect that decision. However, the DWRRA directs that we consider “all costs associated with exploring, developing, and producing from the lease.” Hence, we consider certain eligible types of historical costs (i.e., sunk costs) in making this determination if your field did not produce, other than test production, before you submitted a complete application for royalty relief. Allowable historical costs are your eligible expenditures from the date of the first discovery of the field up to the date you submit a complete application, plus the costs of your discovery well if it is qualified as producible under 30 CFR 250, Subpart A. Attachment C summarizes categories of allowable costs.

We limit the amount of sunk costs we count to those clearly related to developing your field that have not been recovered in previous transactions. We measure sunk costs on an after-tax expensed basis, using the nominal (current dollar) amounts without any interest or discount rate adjustments. Also, we include only sunk costs incurred by current owners of all leases that are both assigned to the field and included in the application.

We don’t count any sunk costs in the profitability test for fields that produced prior to the date you submitted a complete application because they are irrelevant to whether fields continue production or not. We don’t count any historical costs incurred by third parties, like former lease holders. Such costs are hard to verify and are not relevant to the current owner’s decision of whether or not to develop and produce the field. We presume that former owner(s) willingly exchanged the possible future revenues that recover their historic costs for compensation received in transferring their share of the lease(s) to others. In turn, these current owners did not incur these third-party exploration and development costs, but they did or will benefit from their results. Therefore, the costs and benefits of third-party expenses have been fully considered through past market transactions involving the field.

(3) *Volume Test*. If the most economic system for the viability test shows a positve NPV and the best system for the profitability test shows a negative NPV, we will approve your application for royalty relief and compute a volume of production on which to suspend royalties that is sufficient to make your field economic. Applications for Authorized fields are subject to the minimum

royalty suspension volumes specified in section K. This is the third determination.

We won't count sunk costs in computing the royalty suspension volume that will make the field economically viable. To do so would unnecessarily inflate the generous minimum suspension volume for which your field qualified counting sunk costs. Also, in contrast to determining whether you qualify for relief, the DWRRA doesn't specifically state that "all costs" must be considered in determining the correct relief volume.

If we determine that it takes more than the minimum volume suspension to make your field economic, we will calculate the volume suspension using a similar DCF model. We use the resources, engineering design and prospective costs in the application, as verified and potentially modified by us for the viability test, in this calculation. One major difference in the way we conduct this test arises from your obligation to meet certain performance conditions, per 30 CFR 203.76 of the final rule, in order to realize an approved volume suspension. To incorporate that constraint, we base your volume suspension determination only on the most likely scenario and associated resource range in your approved application.

Special Cases: We apply slight variations to the general evaluation procedure described above in cases where ownership changes, where leases are added to a field, and for evaluating expansion projects.

(1) *Ownership Changes*. When changes in lease ownership occur, they can affect how we consider sunk cost. If there is a break in your ownership tenure, we count only your historical costs since you last got a share of the lease. If you've maintained continuous ownership but changed the share of the lease you own, we count your sunk costs on that lease in proportion to the share you owned when you incurred these costs. These principles hold up to the time we make a final determination on your application. Accordingly, a break in ownership on a lease after you submit an application but before we make a final determination could result in a loss of some of the field's otherwise allowable sunk costs. However, after you submit an application, a redistribution of ownership shares on a lease among current or new owners, without a break in ownership, will not affect how we count the allowable costs.

The following table illustrates how we apply these principles to each lease on your field. The table entries represent the percentage ownership of the lease by company and period.

CASE	I	I	II	II	III	III	III
PERIOD	1	2	1	2	1a	1b	2
COMPANY							
A	80	40	80	80	80		40
B	20	20	20		20	60	20
C		40		20		40	40

Period 1 spans the time from when we begin counting sunk costs up to the first change in ownership. Period 2 runs from the end of period 1 until an application is filed. In cases I through III, all period 2 owners are assumed to retain shares during our evaluation process, i.e., during period 3. The results described below would not be affected by a redistribution of ownership shares during period 3 as long as there is no break in ownership in this period. This is the case because there are no sunk costs allowed in period 3, and satisfaction of the continuous ownership requirement would entitle the field to retain all of the sunk costs incurred in period 2.

In case I, we count all of the allowable sunk costs in period 1 since they were all incurred by current owners. Of course, we count all of the allowable sunk costs in period 2 as well since they too were incurred by the current owners.

In case II, we count only 80 percent of allowable sunk costs spent in period 1. We don't count the remaining 20 percent as it is related to a non-current owner. Again we count all allowable costs in period 2.

Case III represents a situation in which there are two changes in ownership up to the time of application, and stable ownership through a final determination. We count only 20 percent of allowable costs from period 1a owing to continuous ownership by company B but not company A. The subsequent break in ownership for company A precludes our counting its costs from period 1a. For periods 1b and 2, we count all costs because there is continuous ownership from period 2 back to period 1b. That accounts for 100 percent of eligible shares in each period. We apply equivalent rules when ownership changes during the evaluation period.

CASE	IV	IV	IV	IV	V	V	V	V
PERIOD	1a	1b	2	3	1a	1b	2	3
COMPANY								
A	80		50	40	80		50	
B	20	100	50	20	20	100	50	20

C				40				80

In case IV, we have two breaks in ownership--one before the application is submitted (period 1b) and the other after submission, but before we make a final determination (period 3). No sunk costs are applicable in period 3. We count all allowable sunk costs in period 2 and in period 1b because all owners in those periods have maintained continuous ownership. We count only B's 20 percent of sunk costs from period 1a because A was compensated for its costs during period 1a in the transfer of all its ownership after that point.

The final case V is identical to case IV, except that during period 3, when we are evaluating the application, there is a break in ownership. The break in ownership makes companies B and C current owners for purpose of the application. So, we don't count any of A's sunk costs from periods 1a and 2, but we count all of B's sunk costs--50 percent in period 2, 100 percent in period 1b, and 20 percent in period 1a.

To ensure that we include the proper amount of allowable sunk costs in our determination, your application should clearly indicate the historic ownership shares of the current owners for each lease in the application, along with the distribution of allowable sunk costs by lease and time period. Moreover, you should notify us immediately when, during the application review process, there is any change in ownership shares on a lease in your field, with special attention to breaks in ownership. Your failure to clearly, accurately, and timely indicate the historic and current ownership arrangements risks losing any relief that we may grant on the grounds that you provided inaccurate information that is material to our determination.

(2) *Fields Mixing Pre-Act and Eligible Leases*. If your pre-Act lease is on a field that already has a royalty suspension volume for new or eligible leases under 30 CFR 260.110, you may apply to share the volume suspension under conditions specified in 30 CFR 203.60 and 62-63. We evaluate your relief application in much the same manner as described above except that we conduct the three DCF determinations taking into consideration the volume suspension to be used by eligible leases on the field.

Eligible leases (those issued within 5 years after the DWRRA) automatically qualify for the minimum volume suspensions discussed in section K. Its lessee may or may not choose to join with a pre-Act lease on the same field that wishes to apply for relief. The lessee of the pre-Act lease must show good cause for us to waive the requirement that all leases on the field be part of an application for royalty relief. Upon appropriate application by a pre-Act lease on a mixed field, we will evaluate field economics including the suspension volume we judge the Eligible lease will be able to use. This may be the full automatic suspension volume, or it may be less if we decide the Eligible lease will be unable to use its full suspension. Case 4, Section K explains how we allocate a volume suspension if we determine that you qualify to share in the field's royalty suspension volume.

An example may help clarify this description. Suppose lease A (the pre-Act lease) and lease B (the Eligible lease) are on the same field and that lease B entitles the field to a royalty suspension volume of 87.5 million barrels of oil equivalent (MMBOE). If we conclude that lease B can produce that much, we reject an application for relief for lease A if the field is economic with royalty free production of 87.5 MMBOE or less. If we decide that lease B can only produce 40 MMBOE, then we reject lease A's application if the field is economic with royalty free production of 40 MMBOE or less. This approach means we presume any expected profits from lease B offset equivalent loses from lease A, regardless of whether they develop jointly or separately.

Material change conditions on approved relief play a reduced role in this situation. Lease B's status as an Eligible lease, serves to shield its owners from loss or reduction of relief for a material change from the application. In such cases, we will be more inclined to look at a wider set of possible resource and cost paths before approving a relief application. Lease A must still avoid the material change conditions described in section J.

(3) *Expansion Projects*. We evaluate your applications for an Expansion project with the same three determinations on a project specific basis. In contrast to the evaluation of pre-Act leases that did not produce prior to the date of application, we don't count sunk costs in any of the determinations for an Expansion project. Consequently, you do not need to have a CPA certify sunk costs for an expansion project, unless we specifically request it while we are evaluating your application. Further, any royalty suspension volume amounts will apply only to production from your proposed expansion project.

You should note that your receiving a royalty suspension volume on production from a Authorized field doesn't preclude you from obtaining further relief under the pre-DWRRA provisions of the OCSLA, the expanded OCSLA royalty relief provisions created by the DWRRA, or under the significant expansion of production portion of the DWRRA. However, your expansion project should recover reserves which were not considered in our original determination. The reservoirs you intend to recover with the expansion project must have a discovery well, as we do not grant relief for exploratory activities.

<u>*Applicant Inputs:*</u> In general, you the applicant provide the resource, productivity and development data, and the costs we use in the determinations. We devote most of the evaluation period to assessing the appropriateness and consistency of these inputs. The following discussion highlights characteristics that we look for in your submission.

(1) *Resource Estimates*. You should give your interpretations of the underlying geology with probability distributions, reflecting the uncertainties about your field's potential size and production. Pay particular attention to justifying the specific types of probability distri-butions you select from the options available with Crystal Ball in our RSVP v2.1 model, not only for assumption distributions for the resource module but also for productivity and cost assumption distributions for the viability module. We carefully review the raw backup data and may adjust the geological interpretations if we determine others are more appropriate.

We verify your estimates for reserves and resources prior to determining economic viability. Part of our reserve and resources verification involves weighing whether you propose too many or too few reservoirs for development. We may decide to drop reservoirs because they add more cost than revenue to the project. In such cases we will exclude that reservoir's production and drop the associated costs from the analysis. We also drop these costs from the base for your material change performance condition of spending at least 80 percent of the estimated pre-production development costs in your most likely scenario. On the other hand, we may add reservoirs because they would contribute more revenue than cost to your project. In this case we presume that you'll develop the extra reserves in a later phase, so we include the extra costs and revenues after production begins. Where sunk costs are important, we may audit your records as part of our verification.

(2) *Production and Cost Estimates.* You specify production and costs using up to three scenarios (conservative, most likely, optimistic) to reflect uncertainty in the design scale of your final development system. We structured the RSVP v2.1 model to simulate adjustments in cost and scale (e.g., number of wells, throughput capacity) based on the potential results of further delineation and project definition. The three scenarios are designed to correlate resource sizes with cost levels. That is, when larger than expected resource sizes are sampled (simulating better than expected delineation results), high end costs (e.g., larger capacity) also tend to be sampled, and vice versa.

You must use care in configuring the development scenarios in RSVP v2.1. We will insist that the mean of the all-trial distribution of capital costs be no more than 7.5 percent above the capital cost estimate you give for the most likely scenario. Also, we insist that the most likely scenario cover at least 1/3 of all trials. These restrictions ensure that your estimates for the most likely scenario are representative of the uncertainty you face and that your application is not being submitted too early in your decision process.

The 7.5 percent value is derived from one of the conditions under which you may request a redetermination from us of whether you qualify for any or more relief. If your costs rise by more than 20 percent from the most likely estimate in your most recent previous application, you are entitled to a redetermination. That is, 20 percent is the largest capital cost increase that we consider to be consistent with other elements in your development plan. Conversely, a 5 percent cost decrease represents a conservative estimate of the cost savings you may be able to realize. The midpoint of this interval (7.5 percent) represents the largest average deviation of cost that we will allow. Proposals that have costs vary on average by more than 7.5 percent indicate that your application is premature because you are not yet confident enough in your cost estimates to decide whether relief from a 12.5 (or in some cases 16.67) percent royalty is likely to make an unprofitable prospect profitable or not.

The following example clarifies this guidance. Suppose you claim that capital costs (including platform fabrication, installation and well drilling and completion cost) are as shown in the following table.

RSVP v2.1 calculates the distribution of capital costs of all trials. Suppose the mean of this distribution is as shown in the right-end column. The application envisions total capital costs 17.5 percent {[(470/400) - 1] * 100 percent} above the best estimate that your back-up data supports. Looked at another way, your application includes an excessive contingency cost estimate of 17.5 percent. That much unspecified uncertainty indicates that it is premature to tell whether royalties are the difference between profit or loss for your field or project.

Scenario Estimate	Conservative	Most Likely	Optimistic	Mean, all trials
Platform cost	$250MM	$250MM	$250MM	
Confidence interval	$245 to $350MM [-2%/+40%]	$225 to $338MM [-10%/+35%]	$210 to $300MM [-16%/+20%]	$300MM
Number of wells	6	5	5	
Average cost/ well	$36 MM	$30 MM	$28 MM	
Well cost	$216MM	$150MM	$140MM	$170MM
Best estimate of capital costs		$400 MM		$470MM

In this situation, we will reduce by parallel amounts the top end of both your confidence interval on capital costs and the maximum values in your input distributions for average drilling and completion cost by enough so your application does not exceed our 7.5 percent standard. For instance, in the example above, we may find that reducing the upper end of the confidence intervals in all three scenarios by 10 percent (to +36, +31.5, and +18 percent from +40, +35, and +20 percent, respectively) and the maximum possible values in the average drilling and completion cost distributions by a like proportion may be enough to lower the mean of all trials to what we judge to be more reasonable levels (e.g., platform cost of $265 MM down from $300 MM and well costs of $155 MM down from $170 MM. In this case your implied contingency factor would be lowered to an acceptable 7.5 percent {[((265 + 155)/400) - 1] * 100 percent}.

Where you've significantly reduced uncertainty with substantial delineation and planning, we will require that you more extensively document and explain the rationale for average deviation of costs between zero and 7.5 percent. Further, in these instances you may substitute fewer than three scenarios or you may use point estimates in place of ranges or distributions. Your documentation in the various reports should clearly establish the results from such delineation and planning. In cases where you opt to use less than three scenarios, you must identify the most likely scenario.

RSVP v2.1 includes a "loss limit" feature, which adjusts illogical trials. For instance, some random samples drawn when you propose large cost and resource uncertainty may pair very small resource sizes with extremely high development costs. This is unrealistic and you would have aborted development rather than lose the large amount of money the model calculates. The adjusted value used on these trials is the present value of non-construction costs you plan to spend in the first year after submitting the application. A few illogical trials are probably unavoidable with the combination of distributions you can chose, especially when you use only one scenario but the full permitted range of uncertainty. However, too many discarded samples distort the model's estimate of the value of your field. Therefore, we insist that the results of your model run must have no more than 20 percent of the trials discarded. If they do, you should reconfigure some of your inputs to get below that threshold.

We check your production and development scenarios for consistency with the geologic data and cost data during the review. As with the information you provide on reservoirs, in cases where we find that assumptions other than those you provide are more appropriate, we reserve the right to make all necessary changes in the set of inputs. One assumption that we will carefully evaluate is your choice of what resource sizes are associated with the switch from one production and cost scenario to another. When your application doesn't explain the choices made, we may request tolling and clarification. If you cannot provide adequate justifications for your choices, we will investigate others and use those that maximize NPV for the field.

In other cases, we may find it necessary to adjust your assumptions to insure fair and consistent treatment across relief applications. For instance, some proposals may contain unusual arrangements involving deferred financing of development capital. Such cases may include little pre-production investment in the RSVP v2.1 calculation. In such cases you need to relate your deferred financing payments to the cost incurred by the owner of the equipment. We will use the present value of the deferred payment stream set by your contract with the owner to judge whether you meet the cost-performance conditions at the post-production development review. As we gain experience with applications, we may identify similar issues where we need to make adjustments for fairness and consistency. We will carefully review any such adjustments with you and specify them in the final determination letter.

<u>*MMS Inputs:*</u> To treat all applicants alike, we provide you with several of the economic assumptions for oil and gas production to be used in the DCF analyses.

(1) *Price and Discount Rate Assumptions:* The Economic Viability and Relief Justification Report section lists price and discount rate assumptions you are to use. We plan to update at least the price assumptions annually with a NTL or as part of revised guidelines. We use the most recent set of economic assumptions that we issued before you filed your application to make all three DCF determinations.

We derive pricing assumptions from long-term projections of oil and gas prices made by major government and possibly private forecasters. We start with oil and gas price assumptions found in information provided by the Energy Information Administration (EIA), Department of Energy. We expect to update price assumptions annually in the spring, after the requisite data and forecasts become available from EIA. You may adjust our prices for the expected API gravity of your reserves if you document these adjustments as discussed in the Economic Viability and Relief Report section. You should request approval for any other price adjustment and get our written approval before making any other adjustments. We consider any other change that we find to our price assumptions as reason for concluding either that the application isn't complete or that it should be rejected.
We also specify a range of discount rates from which you may choose a particular rate. We allow a choice because projects have different characteristics and operators have different risk preferences reflected in their target rates of return. The range we allow for the discount rate is

based on historical industry returns and reflects before tax returns appropriate to a field with a discovery, i.e., where the risk of not finding oil or natural gas has been eliminated.

(2) *Costing Assumptions*. The Cost Report section describes what we consider reasonable cost items for use in the DCF analysis. As with the discount rate assumptions, we may update individual items when new information supports a change.

We follow the cost accounting structure prescribed for Net Profit Share Leases (NPSL) in 30 CFR 220.011 - 220.015. It specifies allowable costs which we summarize in Attachment C: Allowable Cost Categories. We allow you to count all the costs described there because they benefit the development and operation of your field. They allow you to include reasonable portions of joint costs which rightfully should be allocated to this field. Joint costs mean any of the cost items listed in Attachment C that benefits this field and one or more other operations. Because some joint cost may be difficult to allocate we also allow you to assign a modest overhead amount to certain cost items. We view technical and operations support activities as joint costs to be allocated to the field while finance, administration, and management activities should be covered by the allowed overhead.

We use a stochastic model to handle the uncertainty associated with estimates and allow a potentially generous rate of return on a discovered field. Therefore, you may not claim contingency costs or other cost multipliers specifically intended to characterize uncertainty. Rather, you should use ranges as described above for estimating scenarios for capital costs. We view cost contingencies or multipliers as an ineligible cost as they are an alternative way to consider uncertainty whose use in RSVP, in effect, “double-counts” uncertainty.

<u>*Summary:*</u> You provide the necessary information and demonstrate that your field or project can be made economic with royalty relief using standard assumptions and methodology that we provide. We then verify and employ the same information, assumptions, and methodology to evaluate whether your field or project is economic without relief, to confirm that royalty relief can make an your otherwise uneconomic field or project economic, and to compute the magnitude of relief you need to make the field or project economic. All of these determinations are based on forecasts that determine the value of your field, except that certain sunk costs may be included in the profitability test.

In general, we framed both the qualification test and relief volume calculation following the principle that the DWRRA aimed to give substantial, but not excessive, incentive to develop marginal fields or projects. Thus, our economic tests are structured so as to minimize the error of rejecting relief for a field that really should qualify, and the volume calculation is structured so as to minimize the error of giving more volume suspension than is necessary to make a field economic. That is, our calculation of volume suspension tends to give the minimum volumes unless there is strong evidence that a larger amount is needed. Our calculation has this tendency because we exclude sunk costs and because we set an upper bound on the discount rate.

I. Redeterminations (supplements 30 CFR 203.74-75)

You may request that we reconsider denial of an application or reconsider the size of the royalty suspension volume granted in an approved application. We make available a redetermination, before you start the new production subject to the royalty suspension, if there is a significant change in the factors upon which we made our original determination. You may request a redetermination only in the following cases:

1. There is a change in your resource information (e.g., gross resources, quality, flow rates) that is of sufficient magnitude that the results of our initial determination would have been materially different had the previous complete application included the new data. The regulation says the new resource information must result from new G&G activity such as a new well or new 3-D seismic data that did not exist at the time of the previous application. Reinterpretation of existing data doesn’t qualify as a significant change in resource information. You may use a change in resource information to qualify for only the first redetermination on your field. Additional redeterminations are available only for changes 2. and 3. below.

2. Average annual prices of oil and gas fall by more than 25 percent below their level at the time of your most recent previous application. We determine these averages as follows.

   (a) Calculate the arithmetic average of closing prices for light sweet crude and for natural gas on the New York Mercantile Exchange (NYMEX) for the most recent 12 calendar-months.

   (b) Weight the average prices for oil and gas calculated in (2)(a) above by the volumes of oil and gas (in barrels of oil equivalent) identified in the most likely development and production scenario you used for the viability test (see Production Report section) in your most recent previous application for royalty relief. For example, if your most likely scenario foresees a development that will produce 80 percent natural gas and 20 percent oil, we weight the average closing prices of natural gas and oil prices for the preceding 12 months by 80 percent and 20 percent, respectively, in calculating the combined price.

   (c) Perform the same calculations in (a) and (b) above, but use the arithmetic average of closing prices for light sweet crude and for natural gas on the NYMEX for the 12 calendar-months preceding the date you filed your most recent previous application.

(d) If the weighted average price calculated under (b) is more than 25 percent less than the weighted average price calculated under (c) , you are entitled to a redetermination.

3. Prior to starting construction of the development and production system, you increase your estimate of the eligible development costs for the most likely scenario by at least 20 percent over your corresponding estimate in your most recent previous application. You should fully explain why development costs increased and how you estimated the size of the increase in your application for a redetermination.

Your request for a redetermination needs to include a complete new application in accordance with section F. We will evaluate the request to determine if you’re eligible for a redetermination. If you are, we will review the redetermination application in accordance with section G and evaluate it in accordance with section H. Be aware that if you request that we reconsider the size of a royalty suspension volume we granted, you risk losing that volume.

J. Changes in Material Fact (supplements 30 CFR 203.70, 76-77 & 90-91)

We reserve the right to withdraw our approval of or reduce the size of your royalty suspension volume if there is a change in material fact. Withdrawal or reduction of relief serves two relatively modest purposes. One, it replaces more complex "look-back" procedures for correcting errors in our relief assessments that are inevitable in analyses based on forecasts. Two, it fosters applications with reliable information by encouraging you to have done enough delineation and planning so that you are willing to be held to a particular approach, schedule, and cost estimate.

We use specific performance conditions to identify whether or not a change in material fact has occurred. We don’t expect these performance conditions to be perfect predictors of only those changes that would have reversed results of the original analysis. Many sets of changes could evolve that in combination would alter results or offset each other. However, we believe that the limited, but specific performance conditions that we’ve selected balance our obligation to protect the public interest with your right to know ahead of time what you must do to keep relief. Our relief approval notice to you will define the specific performance conditions which you must meet in order to retain your royalty relief.

Generally, we will withdraw an approved royalty suspension volume for any one of the following material changes.

1. You change the type of development system from the one you proposed in the approved application. We presume you are sufficiently committed to the proposed system that you are comfortable being bound to it as a condition of relief. A change from that system invalidates the basis on which we determined your need for royalty relief because it indicates that we evaluated the wrong system. It is immaterial whether or not a substituted system, had we evaluated it, would reverse the original approval. The following list of currently distinct systems illustrates possible changes in the type of development system:
   a. from a dedicated production system to a shared one (e.g., stand-alone platform to tieback);
   b. from a system with well heads on deck to one with well heads on the seafloor;
   c. from a fixed platform to a floating production system;
   d. from a TLP to a Spar.

2. You don't start construction of the development and production system described in your application within one year of the date we approved your application, notwithstanding any suspensions of operations or production. A longer delay invalidates the basis on which we determined your need for royalty relief because it indicates that the evaluation was done prematurely. Again, it is immaterial whether or not the delay would reverse the original approval. However, because delays can occur for reasons beyond your control, you may request up to a one year extension of this deadline as specified in section M.

To verify that conditions 1 and 2 above have been met, you need to give us evidence of a timely commitment to the approved development and production system in the form of a fabricator confirmation report.

For a production and development system acquired as a conventional purchase of a newly built facility, this report should include three items:

1) a copy of the contract(s) under which the fabrication yard is building the approved system for you,

2) a letter from the contractor building your system to our Regional Supervisor - Production and Development certifying when construction has started on a specific system, and
3) evidence that you've paid an appropriate down payment or equivalent manifestation that you've started acquiring the approved development system.

For unconventionally acquired systems (e.g., refitted existing facilities, leased facilities, farmed-in arrangements, etc.) we will specify in the approval letter what equivalent evidence you should give us of timely commitment.

3. (a) You incur actual development costs before commencing production, other than test production, that are less than 80 percent of your estimated pre-production development costs for the most likely development and production scenario in your approved application. RSVP v2.1 calculates this estimate for you. We use a post-production development report to determine whether your actual capital costs meet this threshold. Pre-production expenditures of less than this share of the costs planned for the most likely scenario invalidates the basis on which we determined your need for royalty relief because it indicates that our evaluation over-weighted a high cost option. However, if you inform us of the development cost discrepancy in the post-production development report, you are entitled to 50 percent of the approved royalty suspension volume with no further action required.

   (b) If your royalty suspension volume resulted from a redetermination based on a change in capital costs, as discussed in section I, we will withdraw approval of the application if actual development costs are less than 90 percent of the estimated development costs in the most likely development and production scenario in your approved application. You'll not be permitted to retain any of the approved royalty suspension volume. Second chance applications have had the opportunity for additional, more careful delineation and planning.

To verify condition 3, you need to give us a post-production development report within 60 days after the start of new production. It certifies the accuracy, completeness and conformity to the detail, as specified at paragraph j of the Cost Report section, of the information you provide. Our Regional Director for the GOM may extend your due date for up to 60 days. This report should compare actual expenditures, between the date you file your application and the date you start new production, with the comparable estimates from your application’s most likely development and production scenario. If your post-production report shows that you violate the cost performance condition in 3 (a) you may keep half of the relief we gave you.

Our ability to enforce these performance conditions is constrained in the case of fields that mix pre-Act lease(s) with Eligible lease(s). If the Eligible lease(s) does participate in the application, it keeps its automatic relief regardless of whether subsequent development violates the application. Only the pre-Act lease(s) loses all relief for a change of the proposed development system or excess delay in starting fabrication. As for pre-production costs, we require that the pre-Act lease (s) certify all pre-production costs for the field. The pre-Act lease(s) keeps all its share of relief if this total is at least 80 percent of the application’s estimate of these costs. If this total is less than 80 percent of the application estimate, it must start paying royalties when field production reaches ½ the volume suspension the field was granted in the approved application. If only some pre-production costs are certified (e.g., the Eligible lease(s) does not certify its share) , the pre-Act lease(s) loses all relief if the costs it certifies are less than 80 percent of the application’s estimate. The logic here is that the post-production report is inaccurate because it is incomplete, so all relief subject to the approved application is revoked.

If we grant a good cause exception for Eligible lease(s) on the field not to participate in the application, we then hold the pre-Act lease(s) to what it proposed in the application, just as above. The Eligible lease(s) has the automatic suspension volume but is excluded from any relief approved as result of the application, so its performance or lack of is immaterial.

We will rescind our approval of your royalty suspension volume and revoke your relief as of the date we approved it if:

(1) You fail to submit the fabricator confirmation or the post-production development report,
(2) We discover that you spent less than 80 percent (90 percent in a redetermination) of your estimated development costs and you did not notify us of this fact in your post-production development report, or
(3) We find that you provided false historical information or intentionally inaccurate data that was material to our granting royalty relief.

You owe royalties and late payment interest determined under 30 U.S.C. 1721 and 30 CFR 218.54 on all volume of production on which royalty was not paid. You also may be subject to penalties under other provisions of the law.

When we withdraw your previously approved royalty suspension volume for reasons other than that you submitted false information or intentionally inaccurate data, you may initiate a new application for a suspension volume if you meet one of the qualification conditions described in section I. We review and evaluate the new application in accordance with sections G and H above. However, we count actual development costs as sunk costs in the subsequent analysis. To minimize the conversion of costs from prospective to sunk, you may renounce relief (e.g., in anticipation of violating one of the material change withdrawal conditions) and reapply after qualifying under one of the qualification conditions in section I.

K. Volume Suspensions and Allocations (supplements 30 CFR 203.69 & 71)

This section explains how we apply the royalty suspension volumes in section 302 of the DWRRA to production from your pre-Act lease. For purposes of this section, any volumes of production that are not royalty bearing under the lease or the regulations in this chapter don’t count against royalty suspension volumes. Also, for purposes of this section, production includes volumes allocated to your lease under an approved unit agreement. The following provisions apply only to those leases that have applied for and received a royalty suspension volume under section 302 of the DWRRA.

Minimum Suspension Volumes: Royalty suspension for minimum volumes of production are mandated for Authorized fields. We determine the water depth of a field by the water depth delineations in the version of the “Royalty Suspension Areas Map” and the FNML that are current at the time of your application. If your application for the field includes leases in different water depth categories, we apply the minimum royalty suspension volume associated with the deepest lease. The minimum royalty suspension volumes are:

(a) 17.5 MMBOE for fields in 200 to 400 meters of water;
(b) 52.5 MMBOE for fields in 400 to 800 meters of water; and
(c) 87.5 MMBOE for fields in more than 800 meters of water.

Termination of royalty suspension volumes - Your royalty suspension will continue until the end of the month in which the cumulative production from the applicable leases in the field or Expansion project reaches the approved royalty suspension volume. We intend to provide monthly field production data to lessees in a field or Expansion project who request it when their field has almost produced its suspension volume. However, these data may not become available until a field or Expansion project production approaches or exceeds the royalty suspension volume. Nonetheless, you still owe royalties on the last day of the second month following the month in which cumulative production reaches the royalty suspension volume. Any royalties paid late will be subject to interest pursuant to 30 CFR 218.54.

Allocation Rules: Fields in deep water may consist of one or more leases, including leases issued before and after November 28, 1995 and leases which are either producing or nonproducing. We follow certain general principles to ensure that royalty relief adheres to the provisions of the DWRRA. These principles are described below.

1. A field that produced from any current lease before November 28, 1995 isn’t entitled to a volume suspension by our establishing relief on an eligible lease or by our granting relief to a pre-Act lease.

2. A field is entitled to at most one volume suspension associated with an Eligible lease or a pre-Act ease with an approved application. Once that field’s royalty suspension volume is authorized, the simple addition of Eligible or pre-Act leases to the field won’t change the total royalty suspension volume available to that field. This is the case even if the royalty suspension volumes associated with any of the new leases exceed the authorized royalty suspension volume on the field. Such a situation could occur if a new eligible lease has been issued with a higher royalty suspension volume than an earlier issued eligible lease on the field , or a new pre-Act lease has been found to reside in deeper water depth category than the leases previously included in the field when royalty suspension volume was authorized.

3. A field with an authorized royalty suspension volume as a result of establishment of relief from an eligible lease may have its relief amount increased. This would happen if we grant a royalty suspension volume to a pre-Act lease on the field that exceeds the established amount of relief on the field. In these cases, all Eligible and pre-Act leases approved for royalty relief would then share in the newly determined higher royalty suspension volume for the field, i.e., the amount of relief granted on the pre-Act lease.

4. Pre-Act leases never automatically share in the relief established on the field by Eligible leases. They need to apply for and be granted relief in order to share in the authorized relief.

5. Pre-Act leases simply added to a field with an existing royalty suspension volume may automatically share in that relief only if the field's authorized relief resulted from an approved application that grants relief on a pre-Act lease. To claim the right to share in relief, the added lease should file the short form application described in sections F.

6. All of the Eligible and pre-Act leases approved for royalty relief on a field may share in any remaining royalty relief authorized for the field.

7. The addition of a lease to an expansion project that has been granted a royalty suspension volume won't change the project's royalty suspension volume.

8. A royalty suspension volume may only be granted if your entire lease is west of 87 degrees, 30 minutes west longitude. A field that lies on both sides of this meridian receives a royalty suspension volume only for those leases lying entirely west of the meridian.

The following cases illustrate how we apply these principles to determine how much royalty suspension volume is available to a field and to distribute this volume among the leases on the field.

Case 1. If your field consists of a single pre-Act lease and we approve your application for royalty relief, you owe no royalty payment on production from the lease up to the royalty suspension volume we granted.

Case 2. If your field consists of more than one pre-Act lease and we approve your application for relief, all pre-Act leases owe no royalty payment until their cumulative production equals the suspension volume we granted. The royalty suspension volume for each lease equals its actual production (or production allocated under an approved unit agreement) until cumulative production equals your field's suspension volume.

Case 3. If your pre-Act lease or an Eligible lease is added to a field that has been granted a royalty suspension volume as a result of an approval of an application from one or more pre-Act leases, the field's royalty suspension volume won't change, even if your added lease is in deeper water. Your added lease may receive a royalty suspension volume only to the extent of its production before the cumulative production from the field equals its approved royalty suspension volume.

In this case, the rule doesn't require that your added pre-Act lease submit the full application that the original applicants did. A full application isn't necessary because we've already evaluated the field and see no need to reevaluate that determination. Accordingly, your added pre-Act lease can apply for relief by filing the Administrative Information report with the GOM Regional Office.

Case 4. If your pre-Act lease is part of a field that has a royalty suspension volume for Eligible leases under 30 CFR 260.110, you cannot share in this relief unless a joint application pursuant to 30 CFR 203.60 and 62-63 and section F is submitted and approved. We will waive the joint application requirement if you show good cause for the waiver. Unlike the request for a redetermination for a larger volume suspension, your application for additional relief in this case won't need to forfeit the existing relief. However, we will include the value of the existing relief in our evaluation of your application for the additional relief. If your application meets the economic viability tests, all of the leases share the single new royalty suspension volume until total cumulative production from the field attains that royalty suspension volume.

Case 5. Your lease may receive more than one royalty suspension volume. You may get a suspension volume under this rule for each field that includes your lease and that meets the evaluation criteria described under section H. Also, you may apply for additional relief for a project to significantly expand production, even if we already granted a royalty suspension volume to the field that encompasses that project. However, your expansion project should anticipate recovering reserves which we didn't consider in making our original determination. Unlike a redetermination for larger relief, applications for relief for significant expansions don't risk loss of any unused part of the earlier relief.

For an Expansion project that qualifies for a royalty suspension volume, the rule applies as follows:

Case 6. If your pre-Act lease is the only lease on the project and we approve your application based on significant expansion of production, you owe no royalty payment on the incremental production from the project until that production equals the royalty suspension volume we granted.

Case 7. If your project to significantly expand production includes more than one lease and your application is approved, no lease owes royalties on incremental production from the project until the lessees' cumulative production from the project equals the suspension volume we granted. The royalty suspension volume for each lease equals its actual production (or production allocated under an approved unit agreement) from the project until cumulative production equals the project's suspension volume.

L. Audits (supplements 30 CFR 203.89 & 91)

We may conclude that an audit is necessary to evaluate an initial application or a redetermination. This conclusion is most likely for applications that have large sunk costs and small estimated losses under the economic determination. If this contingency should occur, we may request that the 180-day evaluation period be tolled from the time you receive notice until you provide all the records necessary to conduct the audit. All terms of the relief contract are subject to audit. See 30 CFR 203.81 or the Cost Report, paragraph K for certification requirements.

Your post-production development report is also subject to audit. We may use such audits to help confirm that a change in material fact, section J above has occurred, as well as to determine the applicability of any possible penalties.

M. Appeals (supplements 30 CFR 203.79)

30 CFR 203.79 DWRR rule specifies the three kinds of appealable decisions that bear on our relief determinations and redeterminations -- our field designations, whether to extend fabrication deadlines that you must meet to keep relief, and our judgments on your eligibility for relief and on the appropriate size of your royalty suspension volume.

We use a staged consultive process for designating a lease as part of a field. As explained in section D, our GOM Regional office will contact affected lessees and offer them a chance to review and discuss the proposed designation before finalizing a new field designation or a change to an existing one. Our Regional office's final lease designation on a field may be appealed to the Director, MMS, in the same manner bid rejections are appealed. You should file a written request for this administrative review within 15 days of our notifying you of such designation. The Director's response to this request, either affirming or reversing the earlier decision, cannot be appealed further within the Department of the Interior.

If you are unable to comply with the performance condition specified in section J 2 above for reasons beyond your control (e.g., strike at the fabrication yard or weather caused delays in construction), you may file a written request with the Director, MMS for an extension of up to one year to comply. Again, the Director's decision on this request is the final decision of the Department.

Except as explained above, our determinations and redeterminations are final agency actions. You are not entitled to further administrative review, including Secretarial review. Like all final agency actions, our decisions are judicially reviewable under Section 10(a) of the Administrative Procedures Act (5 U.S.C. 702). You should file your request for judicial review of our determination or redetermination under 43 U.S.C. 1337 (a)(3)(c) within 30 days of our decision.

N. Other Issues (supplements 30 CFR 203.73 & 78)

Gas-to-oil conversion factor - Your royalty suspension volume is measured in barrels of oil equivalent (BOE). For the purposes of this rule, 5.62 thousand cubic feet of natural gas equals one BOE. We measure natural gas in accordance with 30 CFR 250, Subpart L. We have traditionally used this conversion factor in the GOM and it is the same ratio used in 30 CFR 260.110(d)(11) for calculating royalty suspension volumes for Eligible leases.

Non-royalty bearing production - We don’t count any lease-use production that otherwise isn’t subject to royalty toward the royalty suspension volume.

Price escalation clause - Section 302 of the DWRRA directs us to retract royalty relief during periods when prices are very high. Specifically:

1. If in the previous calendar year the arithmetic average of the closing prices on the NYMEX for light sweet crude oil exceeds $28.00 per barrel, as adjusted in paragraph 3. of this section, we retract royalty relief on the oil portion of your production.

   a) You owe royalties at the lease stipulated royalty rate on your previous years' production of oil from a field with approved volume suspension. This production will count as part of the established royalty suspension volume. You should pay royalty due plus interest by January 31 of the current calendar year, in accordance with 30 U.S.C. 1721 and 30 CFR 218.54, on any volume of oil from the previous year for which you did not pay royalty.

   b) You also owe royalties on all your oil production in the current calender year. However, if the arithmetic average of the closing prices on the NYMEX for light sweet crude oil for the current calendar year is $28.00 per barrel or less, as adjusted in paragraph 3. of this section, we will refund or credit with interest royalties you paid that year on any royalty suspension volume for oil production.

2. If in the previous calendar year the arithmetic average of the closing prices on the NYMEX for natural gas exceeds $3.50 per million British thermal units (Btu), as adjusted in subparagraph 3 of this section, we retract royalty relief on the natural gas portion of your production.

   a) You owe royalties at the lease stipulated royalty rate on your previous years' production of natural gas from a field with approved volume suspension. This production will count as part of the established royalty suspension volume. You should pay royalty due plus interest by January 31 of the current calendar year, in accordance with 30 U.S.C. 1721 and 30 CFR 218.54, on any volume of natural gas from the previous year for which you did not pay royalty.

   b) You also owe royalties on all your natural gas production in the current calender year. However, if the arithmetic average of the closing prices on the NYMEX for light sweet crude oil for the current calendar year is $3.50 per million BTU or less, as adjusted in paragraph 3 of this section, we will refund or credit with interest royalties you paid that year on any royalty suspension volume for natural gas production.

3. We escalate the prices referred to in paragraphs 1 and 2 above for any calendar year after 1994 by the percentage by which the implicit price deflator for the gross domestic product has changed since 1994.

Administrative Report
(supplements 30 CFR 203.83)

a. General

You use this report to identify your field and to summarize its background and what relief you seek.

b. Format

This report should be a hard copy text, with separate numbered paragraphs for each of the boxes in the following table. Any attachments, such as for paragraph 4 should immediately follow the relevant paragraph. You should mark any data or information you consider to be proprietary.

Administrative Information
Field Name
Serial number of leases in the field, names of the title holders of record, the lease operators, and the identification of whether the field/lease is part of a unit
Company designation, the API number, location and status of each well that has been drilled on the field/lease or project
Location of any new wells proposed under the terms of the request
Description of field/lease history
Full information as to whether royalties or payment out of production will be paid to anyone other than the United States, the amount to be paid, and the amount of reduction in such payment if relief is granted
Your opinion as to the amount of relief needed to make the field or project economic
For an Expansion project, confirmation that a DOCD or supplemental DOCD has been approved
A narrative description of the development activities associated with the proposed capital investments and an explanation of proposed timing of the activities and the affect on production

[2] If you have relief and seek more, we ask that this opinion be supplemented with a certification that you are voluntarily relinquishing any previous relief.

Economic Viability & Relief Justification Report
(supplements 30 CFR 203.85)

a. General

You use this report to show that your development would be viable (have a positive before tax net present value or NPV) without royalties when using our RSVP model and the economic inputs we supply. Costs you incur before the date of application are not relevant for this report. You are not to use ineligible costs as defined in the Cost Report section in this DCF analysis either. Attachment D explains how to get the RSVP model along with documentation.

You may use your own model in addition to ours if you can justify why our model doesn't adequately represent your situation. However, we reserve the right to use our model in the evaluation and subsequent determination.

b. Economic Assumptions

Under the regulations, you are required to use the economic assumptions listed and discussed below. They will be updated periodically by the use of an NTL. All your other inputs to this model should be justified by the G&G, Engineering, Production, and Costs Reports discussed elsewhere in these guidelines.

Parameter	Minimum	Most Likely	Maximum
Starting Oil Price ($/bbl)	$8.25	$10.75	$13.18
Starting Gas Price ($/MCF)	$1.67	$1.77	$1.87
Real Oil Price Growth Rate 1	6.5%	7.4%	7.9%
Real Oil Price Growth Rate 2	0.3%	0.9%	1.3%
Real Oil Price Growth Rate 3	0.3%	0.9%	1.3%
Real Gas Price Growth Rate 1	4.1%	4.4%	4.7%
Real Gas Price Growth Rate 2	0.1%	0.7%	1.3%
Real Gas Price Growth Rate 3	0.1%	0.7%	1.3%
Real Cost Growth Rate		0%	
Discount Rate Range	10%		15%

Parameter	Value
Year 2nd Scenario Starts	2007
Year 3rd Scenario Starts	2020
Base Year for Starting Price	1999
Federal Income Tax Rate	35%
Random Number Seed	104
Overhead Cost Allowance	5%

Starting Prices - The RSVP model selects starting oil and gas prices for each trial from triangular distributions with the parameters shown above. We determine these prices using the Refiner Acquisition Cost for imported crude in the Petroleum Administration for Defense District (PADD) III and the natural gas wellhead price, compiled by the DOE/EIA. The starting oil prices are independent random variables. The starting gas prices are dependent on the starting oil prices with a +1 correlation factor.

Price Adjustments - Starting oil prices apply to 30° API gravity crude oil. Starting gas prices apply to 1,028 Btus per cubic foot of gas. You should certify the existence and specify the size of any gravity differences or Btu content differences between the expected product of your field and these standards. You may specify these quality differences as distributions.

The RSVP model computes oil quality adjustments from the 30° API basis, using the following table.

Oil Price Quality Adjustment Table

API Gravity	Price Adjustment	API Gravity	Price Adjustment
65	($2.13)	41	$0.87
50.8	$0.00	35	$0.75
50	$0.12	30	$0.00
45	$0.87	0	($4.50)

The model interpolates the price adjustment it uses for gravity values between those in the table. For example, if the model samples your crude oil gravity on a trial as 37.6, then it linearly interpolates between price adjustment values $0.75 and $0.87 using the following equation:

[((37.6 - 35)/(41 - 35)) * (0.87 - 0.75)] + 0.75 = $0.802

The model would then increase whatever starting oil price it picked on that trial by $0.802.

The RSVP model also increases or decreases the starting gas price when you specify a BTU content above or below the standard of 1,028 BTU per cubic foot of gas. The size of the adjustment depends on the price and hydrocarbon content sampled on each trial. For example, if the model picks a BTU content of 950 BTU/cf together with a starting gas price of $2.00/mcf, it adjusts the starting gas price actually used on that trial by the ratio of trial-specific BTU content to the standard BTU content (950/1,028). The resulting starting gas price used on this trial would be $1.85, i.e., $2.00 * (950/1,028).

Real Price Growth Rates - We base these annual rates primarily on long-term oil and gas price projections inherent in the three world price scenarios published in the DOE/EIA Annual Energy Outlook. When we believe it is appropriate, we adjust by projections from other major forecasters. We may use decline rates (negative growth rates). The real gas price growth rate 1 (RIGP1) has a direct dependency on the real oil price growth rate 1 (RIOP1). The real oil price growth rate 2 (RIOP2) has a direct dependency on RIOP1, and RIGP2 has a direct dependency on RIOP2.

Real Cost Growth or Decline Rates - We may use an annual rate to represent an expected change in costs. This change may be partially related to the expected price changes. Cost growth rates are generally some fraction of the price growth rates. Decline rates may also be employed.

Year Scenario Starts - The year the second and third economic scenarios commence.

Discount Rate Range - A range of risk-free annual, real before-tax rates from which you choose a value to use for the various DCF analyses. The value you pick will also be used for all other analyses performed in connection with the application.

Tax Rate - The federal income tax rate we use for determining after-tax sunk costs.

Random Number Seed - We specify an arbitrary seed value to start the random number generator in the model. We do this to allow for output reproducibility.

Overhead Cost Allowance - We specify a modest overhead allowance rate that you may use for Labor, Material, Abandonment and Other Costs categories for joint cost items which you are unable to clearly allocate to your field.

c. Cash Flow

You should provide your output from running our RSVP model. If you use your own model as well, at a minimum the additional data you should provide includes the discount rate you select and columns showing; annual oil production, gas production, oil revenue, gas revenue, total gross revenue, oil transportation costs, gas transportation costs, operating costs, capital expenditures, total net revenue, before-tax cash flow without royalties, overrides, sunk costs, and ineligible costs. Also you should show the before tax NPV your model calculates or implies.

You should show that all costs, gross production, capital costs, and scheduling are compatible with the data you provide in the G&G, engineering, production, and cost reports.

d. Format

You should provide the input data in the RSVP model format specified in its documentation on a 3.5 inch diskette. You should also give us a hard copy of your output results in the RSVP model format to ensure the results we obtain are the same. See Attachment D for a schematic illustration of the RSVP Model layout. You should mark on the hard copy as well as electronic files any data or information that you consider proprietary.

e. Table

The table below is provided for quick reference.

Deep Water Royalty Relief Economic Viability Report	
Economic Assumptions (Provided by MMS)	- Starting oil and gas prices - Real price growth - Real cost growth or decline rate, if any - Base year - Range of discount rates - Tax rate (for use in determining after-tax sunk costs)
Price Adjustment	- Quality adjustments for gravity
Projected Cash Flow Analysis as of Application Date Using Annual Totals and Constant Dollar Values	- All costs, gross production, and scheduling should be consistent with the data in the G&G, engineering, production, and cost reports - The up to three development and production scenarios (conservative, most likely, and optimistic) you provide in the various reports should be consistent with each other and your proposed development system - Oil/gas production - Total revenues - Capital expenditures - Operating costs - Transportation costs - Before-tax net cash flow
Discounted Values	- Discount rate used that you select from within the range we prescribe - Show before-tax NPV without royalties, overrides, sunk costs, and ineligible costs

Geologic and Geophysical Report
(supplements 30 CFR 203.86)

a. General

You use this report to describe the resources in the field you propose to develop. A number of definitions exist for reserves and resources. In this country, the definitions standardized by the Society of Petroleum Evaluation Engineers (SPEE) are the most common. SPEE figures for proved reserves are generally conservative, despite the inclusion of established improved recovery methods, thus contributing to a large reserve growth. DOE has estimated this growth can be as large as eight times the initial figure. In order to minimize the effects of this conservatism and to provide an analysis that considers the uncertainties involved, we don't mandate a specific definition of reserves and resources. Rather, the model has you list the specific reservoirs you've found along with their attendant risk of occurrence and provide distributions for certain characteristics for each reservoir.

b. Detailed Data

You should provide seismic data, well data, and map interpretations as listed in the table under paragraph g below.

c. Reservoir Data

You develop the reserve and resource distributions for your field using the resource module of our RSVP model. The resource module uses two kinds of estimates that you provide to develop this standardized calculation of the reserves and resources.

One, you should submit probability estimates for the chance of occurrence (constant) as well as the chance that it is all oil or all gas for each reservoir that will be included in the viability and suspension analysis. Since your application is predicated on a discovery well, at least one reservoir always has a 100 percent chance of occurrence.

Two, in order to assist in our data validation, you should also provide probability distributions for acres, net thickness, gas-oil ratio or yield, and oil and gas recoveries per acre-foot for each reservoir. You may use any of the distributions available with our RSVP v2.1 model, but you should carefully defend a choice other than a triangular or lognormal distribution. Where delineation with drilling or seismic data has eliminated your uncertainty about the size of any of these characteristics, you may substitute point estimates for distributions. However, you should explain why other values have no chance of occurrence, if you use point estimates in lieu of distributions.

Also, you may specify the degree of dependency, if any, among the expectations for individual reservoirs as long as you defend the correlation between those reservoirs.

d. Aggregation

The resource module combines reservoir estimates into a resource distribution for your field. The aggregation model uses a random number generator to determine reservoir existence on a specific trial. On each trial where an individual reservoir is found to exist, the module samples the distributions of its characteristics and computes a resource size. Those reservoirs found to exist are then aggregated to get the resource distributions for that trial.

The outputs from this module, which on each trial are represented by a field BOE value with an attendant oil percentage, become the inputs to the viability module of the RSVP model. Thus, the resource module is incorporated into the RSVP model to provide trial specific inputs throughout the economic viability simulation analysis.

Attachment D explains how you can get the RSVP v2.1 model template that you and we use to aggregate this data into estimates of reserves and resources for the purposes of royalty relief evaluation.

e. Consistency

The development system you choose, as well as prospective costs and production profiles are all interrelated and tied to the reserve and resource level. You may specify up to three scenarios (conservative, most likely, and optimistic) to portray scales, costs and production profiles appropriate to different parts of your field's resource distribution. As we explain for the other reports necessary for a complete application, you should develop an internally consistent development schedule, cost schedule, and production profile for each scenario that you submit. Also, you should tie each scenario to a specific range on the resource (BOE) distribution. Provide careful justification for the break points between the scenario ranges that you pick.

f. Format

Our letter to lessees of October 1, 1990, describes the format you are to use for digital velocity surveys. You may submit the rest of the detailed G&G data as described in the table under paragraph g. or, if not indicated otherwise, in the format of any state-of-the-art processing technique that is readable by our GOM Regional office. The distributions put out by the RSVP model will satisfy your requirements under 30 CFR 203.86 (d) or paragraph c above. You should provide additional explanation if you substitute point estimates for distributions for any of the data specified in this section.

You should mark on hard copy as well as electronic files any data or information you consider to be proprietary. See Attachment D for a schematic of the format of the RSVP v2.1 model template.

g. Table

The table below is provided for quick reference.

Geologic and Geophysical Report	
Seismic Data	- Non-interpreted 2D or 3D survey lines (8mm tape) (SEGY format or IES format) - Interpreted 2D or 3D seismic survey lines identifying all known and prospective pay horizons, wells, and fault cuts - Digital velocity surveys - Plat map of "shot points" - "Horizon slices" of potential horizons
Well Data	- Hard copies of all well logs 1" electric log should show: = pay zones and pay counts, = lithologic and paleo correlation markers at least every 500 ft. 1" type log should show: = missing sections from other logs where faulting occurs 5" electric log should show: = pay zones and pay counts and = labeled points used in establishing Ro and Rt 5" porosity logs should show: = pay zones and pay counts and = labeled points used in establishing reservoir porosity or labeled points showing values used in calculating reservoir porosity such as bulk density or transit time - Digital copies of all well logs spudded before December 1, 1995 in either LAS or LIS format - Core data, if available - Well correlation sections - Pressure data, including the maximum shut-in pressure at the wellhead - Production test results - PVT analysis, if available
Map Interpretations	For each reservoir included in the application: - Structure maps, top and base of sand maps showing well and seismic shot point locations - Isopach maps for net sand, net oil, net gas, all with well locations - Maps indicating well surface and bottom hole locations, location of development facilities, and shotpoints - Identification of reservoirs not contemplated for development

Reservoir Data	For each reservoir included in the application: - Probability of reservoir occurrence with hydrocarbons - Probability the hydrocarbon in the reservoir is all oil, and the probability it is all gas - Distributions or point estimates for the parameters used to estimate the reservoir size i.e., acre, net thickness, etc. - Most likely values for porosity, salt water saturation, oil and/or gas volume formation volume factor, and recovery factors (%) - Distributions for oil and/or gas recovery per acre-foot with an explanation or example of how the minimum and maximum values were calculated for each unique calculation - Gas/oil ratio distribution or point estimates for each oil reservoir. - Yield distribution or point estimates for each gas reservoir
Reserves and Resources Data	- Aggregated BOE reserve and resource distributions for the field - Description of anticipated crude quality (e.g., gravity) - Break points on the aggregated reserve/resource distribution showing the portion of the range over which to use each of the up to three (conservative, most likely, and/or optimistic) production profiles specified in the production report

Engineering Report
(supplements 30 CFR 203.87)

a. General

You use this report to elaborate on the design of the production facilities you need to develop this field. We take your submission of such a design as evidence of your belief that the field merits development and qualifies for royalty relief. The development scenarios and timing assumptions you submit in your royalty relief application should be consistent with any and all documents previously filed for activities on your lease. You should describe alternative development options that were considered but not chosen along with the reason for non-selection. You should fully explain the rationale for your choice of the selected approach and show why it is the most economical (least-cost) one. If a different system would be more economical without royalty relief, you should indicate where and how it differs from what you proposed. You should also show that development and production of all the project's recoverable resource were reasonably considered in the formulation of the selected approach.

b. Development Concept

You should provide us with a complete description of the type, size, and location of the system you intend to use along with a schedule for its construction.

c. Planned Wells

You should tell us the number of wells you intend to drill, their measured depths, and their type (platform, subsea, vertical deviated, horizontal) as well as your drilling schedule (number and type by year). Also, you should tell us the intended type for each completion, the intended reservoir for each completion, and your schedule (number of completions by year).

d. Production System Equipment

The production schedule is a very sensitive component of net present value. In the event that the actual production rate exceeds your initial planned rate, we need to know the limiting component(s). You should tell us the production system capacity for oil and gas. Also, you should tell us the number, size, length, and location of any and all flow lines tying together subsea wells and or subsea structures with the producing facility.

e. Multi-phase Development Plans

In some cases, you may intend to develop a field in several phases as opposed to entirely at once. We may or may not agree with such an intention due to considerations such as resource conservation, diligence, technical capability, etc. If a multi-phase plan is submitted, you should describe the conceptual basis for developing in phases as well as the goals and milestones you require to commence subsequent phases. You should also give us a justification for the preclusion of any reservoirs you don't expect to develop. Your justification should include a demonstration of either the technical inability to produce or the uneconomic nature of the reservoir.

f. Uncertainty

We are referring to your uncertainty about the size of the actual reserve and resource and thus the attendant number of wells, initial production rates, decline rates, etc., not any uncertainty about the type of development concept you'll use. You may provide up to three schedules of development (conservative, likely, optimistic). A schedule of development includes the development system construction schedule, drilling schedule, completion schedule, and the production system installation schedule. Make each one consistent with its counterpart production profile (conservative, likely, optimistic) you provide in the Production and Cost reports. If you submit fewer than three distinct scenarios, you should explain why other development scales or schedules are not efficient for part of the possible range of resource size.

g. Format

You should mark on hard copy as well as electronic files any data or information that you consider proprietary. See Attachment D for the RSVP v2.1 model format. We prefer that you provide the data described paragraphs a b, c, d, and e. in hard copy text with separate lettered divisions for each of the applicable sections of this report.

h. Table

The table below is provided for quick reference.

Engineering Report	
Development Concept	- Fixed, floater type, subsea tieback, etc. - Construction schedule
Planned Wells	- Number of wells planned - Type of well (platform, subsea, vertical, deviated,

	horizontal) - Well depth - Drilling schedule - Completion description: normal, dual, horizontal, etc. - Completion schedule
Production System Equipment	- Production capacity for oil and gas and a description of its limiting component - Unusual problems (low gravity, paraffin, sand, etc.) - Subsea structures - Flowlines - Production system installation schedule
Multi-phase Development Plans	- Conceptual basis for developing in phases and goals/milestones required for commencing subsequent phase - Justification for the preclusion of reservoirs not contemplated for development
Uncertainty	- Schedules of development consistent with each of the up to three field production profiles (conservative, likely, optimistic) provided in the production report

Production Report
(supplements 30 CFR 203.88)

a. General

You use this report to justify the future flow rates that you expect for wells from your field. You should explain any significant deviation from flow rates at comparable wells and fields. Your projections may be based on analogy, actual production tests, decline curves, computer modeling, or other accepted engineering methods. However, your discussion in this report should explain the methods used in developing the estimates along with any attendant assumptions.

b. Production Profiles

You should report the expected production for each well completion and the field by year for each year of production for oil, condensate, gas, and associated gas as well as the composite BOE production. You may submit up to three separate production profiles (conservative, most likely, optimistic). Each profile for the field should represent the production schedule you expect if a specific range on the field's aggregated reserve and resource distribution exists (conservative, most likely, optimistic). You should justify these ranges in the G&G Report. Also, you should insure that each production profile for the field is consistent with the applicable (conservative, most likely, optimistic) scenarios used in the Engineering Report and the Cost Report.

You should describe the specific production drive mechanism you expect for each reservoir.

c. Format

You should mark on hard copy as well as electronic files any data or information that you consider proprietary. See Attachment D for the format for the RSVP v2.1 model. We prefer that you submit annual production data by product in hard copy.

d. Table

The table below is provided for quick reference:

Production Report	
Production Profile	- Projected production for each well completion and the field by year for each year of production for oil, condensate, and gas as well as the composite BOE
Uncertainty	- Up to three production profiles (conservative, most likely, optimistic) as described above - Each production profile for the field should be consistent with a specific point on the aggregated reserve and resource distribution and represent a conservative, most likely, and an optimistic case
Miscellaneous	- Production drive mechanism for each reservoir

Cost Report
(supplements 30 CFR 203.81(b) & (c), 89 & 91)

a. General

You use this report to justify and explain how you estimated the various costs that you have and will incur to develop and produce this field. You should limit your costs estimates to the items identified in paragraphs b through f below and report them in the categories listed in Attachment C. We believe they cover all the elements that clearly benefit the development and operation of your field. Allowable costs include the portion of joint costs in those categories that you can reasonably attribute to your field and a 5 percent overhead rate on costs in the Labor, Material, Abandonment, and Other Costs categories. We review your cost estimates, and once validated, use them to evaluate the application. As part of our validation we will consider the consistency of up to three cost scenarios (conservative, most likely, optimistic) with the applicable production and engineering scenarios as well as the applicable reserve and resource ranges. You should document the basis for all your cost estimates (e.g., contract with supplier, cost for a project of similar size and water and drilling depth, vendor estimate, commercially available cost estimating software, etc.). If you expect to encounter any unusual conditions or if you are considering alternative development options that could cause costs to vary significantly from the estimates presented, you should fully describe those conditions or options.

b. Sunk Costs

You should report sunk costs, as defined in Attachment B, for those cost components and elements listed in paragraphs c, d, e, and f below. We count only eligible sunk costs for which you provide documentation. Eligible sunk costs include only those historical costs incurred by you or your current partners in the application, not those of third parties. To help identify which sunk costs we should count, you should report separately by lease the size and timing of proportionate shares and breaks in ownership for all current owners, along with the timing and distribution by lease of the eligible sunk costs.

We count sunk costs on an after-tax, expensed basis using nominal (current dollar) amounts without any interest or discount rate adjustments. We may audit your sunk costs as discussed in sections G and L. You should certify these costs as explained in paragraph k of this Cost Report. We use these sunk costs only in the DCF evaluation for the profitabilty test (as explained in section H) and in determining whether there has been a change in material fact (as explained in section J).

c. Delineation and Development Costs

You should submit all the cost elements for this component listed in the table below paragraph n. You should associate applicable costs with specific reservoirs whenever possible. You may base your estimates on actual costs (such as the cost of previous wells drilled in the field), engineering estimates from vendors, or equivalent costs at analogous projects. Cost estimates should be itemized in an Authorization for Expenditure (AFE) format.

Development cost elements that we use for sunk costs and in the Post-production Report (paragraphs b and k of this Cost Report) are underlined. Specific items that may be included in the cost elements are as follows:

Wells - Rig cost, casing and tubing, mud, consumables, equipment (wellhead valves and other equipment necessary for interaction with topside facilities), services (cement, chemicals, insurance, transportation), drill bits, etc.

Completions - additional cementing, perforating, sand control, packers, etc.

Subsea Completions - wellhead production tree, flowline controls and valves, miscellaneous equipment provided for both cluster and satellite wells, etc.

Production System - where applicable, jacket or compliant tower; hull acquisition, fabrication or conversion; superstructure; installation; topside facilities (production processing equipment; power, utility, and safety equipment; accommodations; wellhead equipment; storage facilities); riser system; subsea drilling template; engineering design; pilings or guidelines; mooring system; conductors; etc.

Flowlines - pipelines between wells and platforms - fabrication, coatings, installation, anode/cathode protection, etc.

d. Production Costs

You should submit all the cost elements for this component listed in the table below paragraph n. You should specify the bases for these costs (historical, engineering estimate, or analogous project). Production cost elements that we use for sunk costs and in the Post-production Report (paragraphs b and k of this Cost Report) are underlined. Specific items that may be included in the elements are as follows:

Operating Costs - your costs for inspection, maintenance, repair, payroll, support and crew transport, insurance, workovers, consumables.

Equipment Leasing - your cost to lease any equipment.

Taxes* - your Federal income, State income, and severance taxes resulting from this field.

Overrides* - royalty overrides and other forms of payment you incurred to acquire a financial position in lease(s) associated with this field.

* We will not use these costs in our DCF evaluations.

e. Transportation Costs

You should submit all the cost elements for this component listed in the table below paragraph n. This component should include all costs, both arm's length and non-arm's-length, that are likely to be allowed as a deduction by MMS for royalty computation purposes, based on existing rules and recent precedents. Include in this component, costs of additional dehydration and compression equipment needed to cope with the colder temperatures and greater distances experienced in deep water and of extra buoyancy added to a floating production platform to accommodate the transportation system equipment. You should specify the bases for these costs (historical, engineering estimate, or analogous project). Transportation cost elements that we use for sunk costs and in the Post-production Report (paragraphs b and k of this Cost Report) are underlined. Specific items that may be included in the elements are as follows:

Tariffs - your cost per bbl or MCF to use a pipeline(s) to bring the product to market.

Trunkline and tieback line costs - your costs for pipe fabrication, protective coatings, anode or cathode protection, appurtenances (pipeline connectors, riser tie- in packages, valve assemblies, pig launchers or receivers), engineering design, installation, compression, dehydration and extra floating platform buoyance. Don't include costs reported in the flowline portion of paragraph c here.

Gas plant processing costs - your costs expended off lease to process the gas to increase liquid recovery.

f. Abandonment

Your should tell us your estimate for future costs to plug and abandon wells and to remove production systems that did not exist at the date of application. Don't include any such costs which you've already incurred at the time of application. You should include an estimate or distribution of prospective salvage value for all potentially reusable facilities and materials.

g. Ineligible Costs

We will not consider certain types of costs in our royalty relief analysis, either due to the requirements of the law or because they are not properly cost associated with the production for which the relief is being granted. A partial list of such costs are your:

1) acquisition costs,
2) royalty relief application fees,
3) lease rentals,
4) exploration costs,
5) damages and loses,
6) taxes,
7) interest or finance charges,
8) legal expenses and fines or penalties,

9) Costs associated with obligations existing before the application (e.g., royalty overrides or other forms of payment for acquiring a financial position in a lease, expenditures for plugging wells and removal and abandonment of facilities existing on the date of application),
10) costs of producing and using hydrocarbons on the lease, and
11) any historical costs incurred by third parties.

We reserve the right to add to this list and to make determinations regarding the eligibility of all costs you submit in the application.

h. Uncertainty

In order to model the uncertainty inherent in applications submitted at an early project stage, you may describe your costs in one of three ways. One, you may provide a separate cost scenario (conservative, most likely, optimistic) for each of up to three field production profiles you listed in the Engineering Report. For the purpose of this discussion, we consider a scenario to be a listing of total costs, in constant dollar terms for the base year, by category as well as an annual scheduling of such costs by category. The base year is the year of application. Two, you may also model uncertainty about capital costs within each scenario by specifying confidence factors (i.e., a minimum and maximum percentage of the scenario value). Three, as with the resource data, you may model uncertainty about drilling, operating, and transportation charges with probability distributions. You must explain the basis you used for selecting the number of scenarios, each probability distribution, and confidence factor you use.

i. Contingency

You may not include explicit contingency factors in your cost estimates. Uncertainty you have about omitted costs items or about future prices for inputs (e.g., rig day rates) should be incorporated into the way you configure your scenarios, cost distributions, and confidence factors. We allow the average of your distribution of capital and well costs to be as much as 7.5 percent above your best itemized estimate for these costs. In effect, we allow you to include up to a 7.5 percent contingency on these costs when they are accounted for in the configuration of your scenarios, cost distributions and confidence factors. Separate contingencies built into your itemized estimates of capital or well costs would constitute a redundant inclusion of uncertainty.

j. Scheduling

You should include, for each of the up to three cost scenarios, an annual listing (in constant base year dollars) of your historical and anticipated cost expenditures by category. The term category is intended to refer specifically to the items in the right hand column of the table in paragraph n.

k. Post-production Development Report

To retain the approved DWRR, you should file a post-production development report within 60 days after you start production. The only exception to this requirement occurs if the our Regional Director for the GOM grants you an extension. You should submit actual costs for all of the elements of the development, production, and transportation cost components (listed in paragraphs c, d, and e above) with supporting records. In addition, you should provide costs by category for each component in the Allowable Cost Report format as listed in Attachment C. We use this information for decisions involving changes of material fact.

l. Certification

You or your authorized representative should certify that all the information submitted in an application or post-production development report is accurate, complete, and that the presentation of data and information conforms to our guidelines. Your application and post-production development report should be accompanied by a report prepared by an independent CPA that expresses at least a qualified opinion that the historical financial information in the application and post-production development report is accurate and that the presentation of data and information conforms to our guidelines. You should identify the individuals in the CPA firm who prepared these reports and make them available to us to respond to questions which may arise regarding the evaluation of your historical information. We reserve the right to also review your records on the historical financial information in your application.

All the non-historical eligible costs you claim should be either direct or allocable indirect costs for the field. You should certify, either by independent review or company official, that all these costs are relevant to the field in question and that only those costs necessary for the proper operation of the field operations have been included.

m. Format

You should submit historic and future cost by element listed in the table under paragraph n. by year in hardcopy or on 3.5 inch diskette. The documentation for the RSVP model shows and explains the model's format for data. In addition to the model cost inputs, you should submit cost data as specified in paragraphs b and j of this report for historical costs and i of this report for future costs. You should mark on the hard copy as well as electronic files any data or information that you consider proprietary.

n. Table

The table below is provided for quick reference.

Deep Water Royalty Relief Cost Report	
Ownership history and sunk costs - certified by CPA	- All documented eligible costs, in nominal (current dollar) amounts, actually incurred subsequent to and including the first discovery well on the field. We count sunk costs on an after-tax, expensed basis - All changes in lease ownership since discovery of the field as well as the timing and distribution by lease of all sunk costs
Delineation and development costs - from historical records, engineering estimate, or analogous project in AFE format and certified by independent review or company official.	- Platform well drilling costs and average well depth - Platform well completion costs - Subsea well drilling costs and average well depth - Subsea well completion costs - Production system (platform) costs - Flowline fabrication and installation costs
Production Costs - historical, engineering estimate or analogous project - certified by	- Operating and processing costs - Equipment leasing costs - Taxes (won't be used in our DCF evaluations)

independent review or company official.	- Existing royalty overrides (won't be used in our evaluation)
Transportation Costs - historical, engineering estimate or analogous project -certified by independent review or company official.	- Oil and/or gas tariffs from pipeline or tankerage - Trunkline/tieback line costs - Gas plant processing costs for NGL
Ineligible Costs	- Acquisition costs - Application fees - Costs associated with prior existing obligations (see paragraph G of the Cost Report)
Uncertainty	- A cost scenario consistent with each one of the up to three field development and production profiles (conservative, likely, optimistic) - If desired, express the uncertainty of capital cost for each scenario with confidence factors and of drilling, operating, and transportation costs with probability distributions
Contingency Costs	- Not allowed
Scheduling	- Provide costs on an annual basis (in real dollars for the base year) for each of the above components
Abandonment	- Estimate the costs to plug and abandon wells and to remove the production system for which costs have not been incurred at the time of application - Include an estimate of the salvage value of reusable facilities and materials
File a post-production development report 60 days after you start the production subject to an approved royalty suspension. Report actual expenditures for the above cost components up to the date production starts. Retain supporting records for these costs and make them available to us upon request.	

Attachment A: Royalty Relief System Summary

INFORMATION ELEMENTS	End-of-life Lease	Deep-water Expansion Project	Pre-Act Deep-water Lease
Application Content 30 CFR 203.51, 62, 81-89 & 93			
Administrative information report	x	x	x
Net revenue and relief justification report (prescribed format)	x		
Economic viability and relief justification report (RSVP model inputs justified with G&G, Engineering, Production, & Cost reports)		x	x
Geological & Geophysical (G&G)report		x	x
Engineering report		x	x
Production report		x	x
Deep-water cost report		x	x
Verification 30 CFR 203.70, 81 & 90-91			
Fabricator's confirmation report		x	x
Post-production development report (approved by certified public accountant (CPA)		x	x
APPROVAL & RELIEF ATTRIBUTES	End-of-life Lease	Deep-water Expansion Project	Pre-Act Deep-water Lease
Approval Criteria 30 CFR 203.50, 52, 60 & 67			
At least 12 of the last 15 months have the required level of production	x		
Already producing	x	x	
Well can produce			x
Royalties for qualifying months exceed 75 percent of net revenue (NR)	x		
Substantial investment (e.g., platform, multiple wells, subsea template)		x	

Determined to be economic only with relief		x	x
Redetermination 30 CFR 203.52 & 74-75			
After 12 months under current rate, criteria same as for approval	x		
For material change in geologic data, prices, or costs		x	x
Relief Rate 30 CFR 203.53 & 69			
One-half pre-application effective lease rate	x		
Zero		x	x
Relief Volume 30 CFR 203.53 & 69			
Average flow for 12 qualifying months	x		
Field suspension volume is at least 17.5, 52.5 or 87.5 million barrels of oil equivalent (MMBOE)			x
Amount needed to become economic		x	x
CONTINGENCY FEATURES	End-of-life Lease	Deep-water Expansion Project	Pre-Act Deep-water Lease
Marginal Royalty rate on Additional Production (amount above the relief volume) 30 CFR 203.53 & 69			
1.5 times pre-relief effective lease rate on additional production up to twice the qualifying amount, and the pre-application effective lease rate for any larger volumes	x		
Original lease rate		x	x
Relief Lost for ... 30 CFR 203.76			
Not submitting post-production report that compares expected to actual costs		x	x
Change of development system		x	x
Excess delay in starting fabrication		x	x
Relief Reduced for ... 30 CFR 203.76			
Spending less than 80 percent of proposed pre-production costs but notifying us in		x	x

post-production report			
Full Royalty Resumes when ...30 CFR 203.54 & 78			
Average NYMEX price for last 12 months is at least 25 %above the average for the qualifying months	x		
Average NYMEX for last 12 months exceeds $28/bbl or $3.50/mcf, escalated by the gross domestic product deflator since 1994		x	x
Relief Ends when ... 30 CFR 203.55 & 69			
Recipient so requests	x		
Lease rate is at the pre-application effective rate for 12 consecutive months	x		
Conditions that we may specify in the approval letter in individual cases actually occur	x		
Amount of relief volume is produced		x	x

Attachment B: Definitions (from 30 CFR 203.0)

Authorized field - A field in a water depth of at least 200 meters and in the Gulf of Mexico west of 87 degrees, 30 minutes west longitude from which no current pre-Act lease produced, other than test production, before November 28, 1995.

Complete Application - The fee specified in 30 CFR 203.3 and an original and two copies of the six reports consisting of the data specified in 30 CFR 203.81, 83 and 85-89, which we've reviewed and found complete.

Determination - Our binding decision on whether your field qualifies for relief or on how large a royalty-suspension volume must be to make your field economically viable.

Draft Application - The preliminary set of information and assumptions you submit to seek a nonbinding assessment on whether a field could be expected to qualify for royalty relief.

Eligible Lease - An Outer Continental Shelf lease that results from a lease sale held after November 28, 1995; is in the Gulf of Mexico in water depths 200 meters or deeper; lies wholly west of 87 degrees, 30 minutes west longitude; and is offered subject to a royalty-suspension volume authorized by statute.

Expansion Project - A project you propose in an approved Development Operations Coordination Document (DOCD) or supplement that will increase the ultimate recovery of resources from your pre-Act lease and that involves a substantial capital investment (e. g., fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well projects, etc.).

Fabrication (or start of construction) - Evidence of your irreversible commitment to a concept and scale of development, including copies of a binding contract between you (as applicant) and a fabrication yard, a letter from your fabricator certifying that construction has begun, and a receipt for the customary down payment.

Field - An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geological structural feature or stratigraphic trapping condition. Two or more reservoirs may be in a field, separated vertically by intervening impervious strata or laterally by local geologic barriers, or both.

Lease - Either a lease or a unit of multiple leases.

New Production - Any production from a current pre-Act lease from which no royalties are due on production, other than test production, before November 28, 1995; or any production resulting from lease-development activities involving a substantial capital investment on a current pre-Act lease under a Development Operations Coordination Document (DOCD)--or its supplement--approved by the Secretary of the Interior after November, 28, 1995.

<u>Nonbinding Assessment</u> - An opinion by us of whether your field could qualify for royalty relief. It's based on your draft application and doesn't entitle the field to relief.

<u>Performance Conditions</u> - Minimum conditions you must meet, after we've granted relief and before production begins, to remain qualified for that relief. If you don't meet each one of these performance conditions, we consider it a change in material fact significant enough to invalidate our original evaluation and approval.

<u>Pre-Act lease</u> - A lease on the Outer Continental Shelf issued as a result of a lease sale held before November 28, 1995; in a water depth of at least 200 meters; and in the Gulf of Mexico west of 87 degrees, 30 minutes west longitude.

<u>Production</u> (for purposes of Deep Water Royalty Relief) - All oil, gas, and other relevant products you save, remove or sell from a tract, or those quantities allocated to your tract under a unitization formula, as measured for the purposes of determining the amount of royalty payable to the United States.

<u>Redetermination</u> - Your request for us to reconsider our determination on royalty relief if we've rejected your application or, if we've granted relief but you want a larger suspension volume.

<u>Renounce</u> - Action you take to give up relief after we've granted it and before you start production.

<u>Sunk costs</u> - Costs (as specified in 30 CFR 203.89(a)) of exploration, development, and production you incur after the date of first discovery on the field and before the date you send in a complete application for royalty relief. Sunk costs also include the costs of the discovery well qualified as producible under 30 CFR 250.111.

<u>Withdraw</u> - Action we take on a field that has qualified for relief if you haven't met one or more of the performance conditions.

Attachment C: Allowable Cost Categories

Associated with the Cost Variables Used to Determine Qualification for Royalty Relief

(supplements 30 CFR 203.89)

The text of these guidelines refers to several different cost variables we use to determine your qualification for royalty relief. Each of these variables consists of expenditures associated with several different cost categories. This attachment summarizes categories of allowable costs, drawn from 30 CFR 220.011 and describes what expenditures we view as eligible costs in the respective cost categories. Our companion guidelines on End-of-Life Royalty relief includes an almost identical attachment (Attachment 1) on allowable costs. *Italics* in this Attachment C denote passages which deviate from Attachment 1 to Appendix II (the End-of-Life Lease guidelines).

Table 1 - Cost Codes and Categories

Cost Code	Cost Category
100	Labor
200	Material
300	Transportation
400	Contract Services
500	Lessee Owned Rentals
600	Insurance
700	Communications
800	Ecological and Environmental
900	Abandonment
1000	Other Costs
1100	Other Credits

Many of the allowable cost definitions we use for royalty relief are the same as those we allow for Net Profit Share Leases (NPSL). Where the definition of terms is identical, we refer to the corresponding cite in the Code of Federal Regulations. In those instances where the definitions differ, we specify the definition appropriate for royalty relief purposes.

Costs associated with Labor, Material, Abandonment and Other Costs categories are eligible for an overhead allowance of 5 percent, slightly more generous than the share allowed during the relief period in the NPSL regulations at 30 CFR 220.012. Other categories tend to be contract costs which already have an overhead included in them. Joint costs and credits should be allocated to the lease in the same manner as described in the NPSL regulations at 30 CFR 220.014.

There are two basic rules you should follow when making decisions on whether to include particular costs in the application. First, we count and you should submit only your costs or portions of your costs that you can validate as necessary for the proper conduct of your lease operations.

Second, we don't allow and you should not submit costs for any obligation *that would continue should lease operations cease. For example, we don't allow installment payments for a capital expenditure that was financed* or the costs of abandonment for pre-existing wells and facilities. These obligations remain regardless of the economic performance of your lease, so they are not considered relevant to whether you continue to produce on an otherwise profitable lease.

A. Labor (cost code 100) covers:

1. Salaries and wages of field employees, first level supervisors, and technical employees employed in the operation of your lease, in the area of your lease.

2. Salaries and wages of technical employees within technical branches of your organization that may not work in the area of the lease but are working "full time" on some particular technical problem or operations aspect of your lease. Excluded from this category are employees assigned a role in your lease's operations as a duty collateral with other duties that do not directly benefit that lease.

3. Salaries and wages of technical employees within technical branches of your organization who are assigned technical tasks directly related to the operation of your lease provided they are supported by adequate time records showing the nature of the task and the hours spent on the task. This is an example of a joint allocable cost.

4. Employee benefits allowable according to 30 CFR 220.011(b)(2-6).

5. Overhead allowance up to 5 percent of the sum of the other costs in this category. This, together with the corresponding amounts in items B, I, and J below is designed to cover your

finance, administration, and management activities appropriate for the field.

B. Material (cost code 200) covers items you purchase or furnish as lease property. We look for the following attributes in costs you claim in this category.

1. You charge or credit material at amounts specified in 30 CFR 220.015. Your purchase and inventorying of material conforms to the conditions and provisions of 30 CFR 220.032.

2. You charge to the lease only such material purchased or furnished as lease property that is consistent with efficient and economical operations. You have not accumulated surplus stocks.

3. You credit to your lease costs for salvaged or returned material.

4. Overhead allowance up to 5 percent of the sum of the other costs in this category.

C. Transportation (cost code 300) covers charges for transportation of employees and material necessary for your lease operations to, from and within the lease area. We look for the following attributes in transportation charges you claim.

1. You only charge transportation costs for material for a distance not greater than the distance from where like material is normally available.

2. You count transportation charges for material shipped from the lease only for lease material and then only to the nearest reliable supply store, barge terminal, or railway receiving point.

3. You do not include expenditures under $200 in transportation charges for material.

D. Contract Services (cost code 400) covers the cost of services and utilities provided to your lease under contract by outside parties and rental charges paid to outside parties for the use of equipment in the lease area in support of lease operations. These services must be provided under an arm’s- length contract as defined in 30 CFR 206. Actual costs, rather than fees, for services provided under a non-arm’s-length contract must be included in the following cost categories. We look for the following attributes in the costs you claim for contract services.

1. The contract services constitute proper and necessary lease operations or support for lease operations.

2. You charge the contract rate for contract services (including consulting services or contracted technical personnel) established exclusively for the lease.

3. You allocate the cost of contracted services shared among this lease and others pro-rata to the applicable leases.

4. You do not count the costs of contract services for research and development.

E. Rental of Equipment and Facilities Furnished by Lease Owner(s) or affiliated parties (cost code 500) covers the use of equipment and facilities which you *own or* acquire that are proper and necessary for lease operations and are not lease property.

1. These may include shore base and offshore facilities, and pipelines from the tract to shore based facilities.

2. The methodology for determining allowable charges for the use of non-lease equipment furnished by the lessee is specified at 30 CFR 220.011(g).

F. Insurance (cost code 600) covers net premiums you pay for insurance you are required to carry for lease operations.

G. Communications (cost code 700) cover the costs of leasing, acquiring, installing, operating, repairing, and maintaining communication systems, including radio, microwave facilities, and computer production controls for lease operations according to the proportion of those costs that are allocable to lease operations.

H. Ecological and Environmental (cost code 800) cover three items.

1. Those costs you incur in the lease area as a result of statutory regulations for archeological and geophysical surveys relative to the identification and protection of cultural resources.

2. Your cost to provide or to have made available pollution containment or removal equipment, including payments to

organizations or funds which supply equipment or assistance in the event of oil spills or other environmental damage.

3. Your costs for the actual control and cleanup of oil spills and resulting responsibilities required by applicable laws and regulations except in cases of your negligence or willful misconduct. We don't allow any costs from an incident resulting in civil or criminal penalties.

I. Abandonment (cost code 900) covers three items.

1. We allow costs associated with abandonment of wells *you plan to drill if we approve royalty relief* but not costs associated with wells existing before *we grant royalty relief*.

2. We allow costs associated with abandonment of a well bore for the purpose of using it to drill into *another* reservoir included in the project and with modification of platform equipment for project specific purposes.

3. Overhead allowance up to 5 percent of the sum of the other costs in this category.

J. Other Costs (cost code 1000) covers costs not included above that you incur in the necessary and proper conduct of the lease operation. You should have any costs in this category specifically approved by the Director, MMS, or appropriate delegated authority. These costs may include up to a 5 percent overhead.

K. Other Credits (cost code 1100) cover credits to lease operations for:

1. Lease property you lease to or use in non-lease operations,

2. Your sale of information derived from test wells and geological and geophysical surveys, and

3. For any and all amounts earned or otherwise due you as a result of lease operations.

In addition to those costs listed at 30 CFR 220.013, the following costs are not allowable:

1. OCS rental payments on the lease(s) in the application.

2. Damages and losses.

3. Taxes.

4. Any costs associated with activities that are exploratory in nature.

5. Civil or criminal fines or penalties.

6. Royalty relief application fees.

7. Costs associated with prior existing obligations (e.g., royalty overrides or other forms of payment for acquiring a financial position in a lease).

Attachment D: RSVP Computer Model Layout
(supplements 30 CFR 203.85)

We've constructed a template model, Royalty Suspension Viability Program (RSVP), for the Economic Viability and Relief Justification report. It is to be used with Windows, Excel version 7 and Crystal Ball version 4.0 software. You may obtain the RSVP template from:

Regional Supervisor for Production and Development
Minerals Management Service
Gulf of Mexico OCS Region
1201 Elmwood Park Boulevard
New Orleans, LA 70123-2394

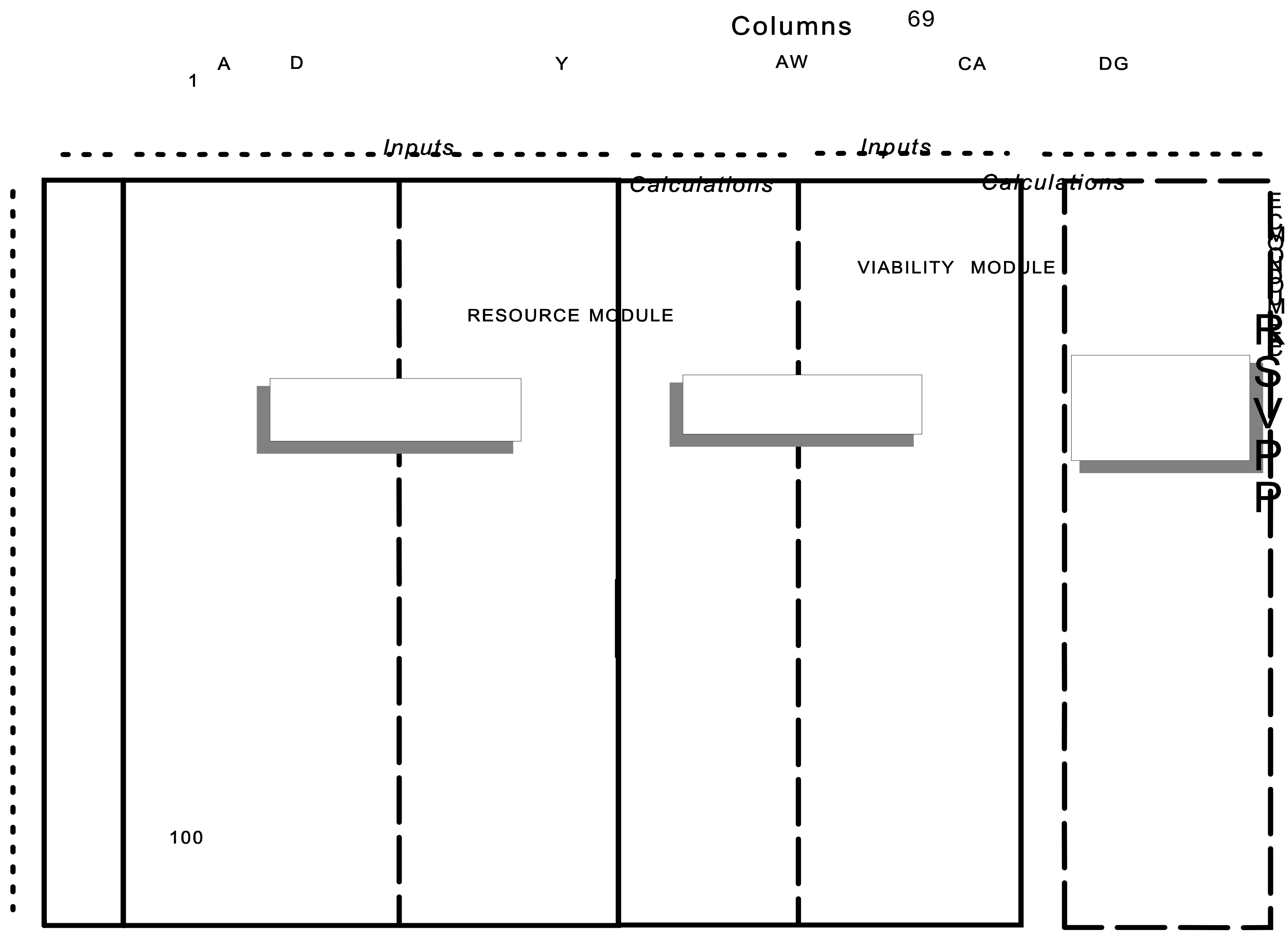
Crystal Ball is a registered trademark of Decisioneering, Boulder, Colorado, (www.decisioneering.com; phone (303) 337-0900 or 800-289-2550; FAX (303) 337-3560).

The RSVP model uses probability (Monte Carlo) methodology to develop a resource estimate from your input data and a net present value for your field from the production profile and cost components you supply. We provide details on how the model works in extensive documentation available with the model.

Also, you may download these guidelines, the model and its documentation from the MMS home page (www.mms.gov). From that screen, you then go to Managing Offshore Resources, Gulf of Mexico, Offshore Information, Royalty Relief Information.

This attachment provides a schematic layout of the template for that model. The Documentation for the RSVP Model offers an example complete with inputs and results. We highly recommend that you confirm the example outputs before proceeding with extensive additional analyses.

The reserve model is integrated into RSVP as shown in the template. You can get resource output distributions in addition to those programed in RSVP by alternative selection of Crystal Ball output parameters as discussed in the model documentation. Outputs of the Resource module are in columns X through AR. Those for the viability module are in columns BX through CW. The inputs and outputs should be provided on a 3.5 inch diskette.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D
Y
AW
CA
DG
Inputs
Inputs
Calculations
Calculations
VIABILITY MODULE
RESOURCE MODULE
100

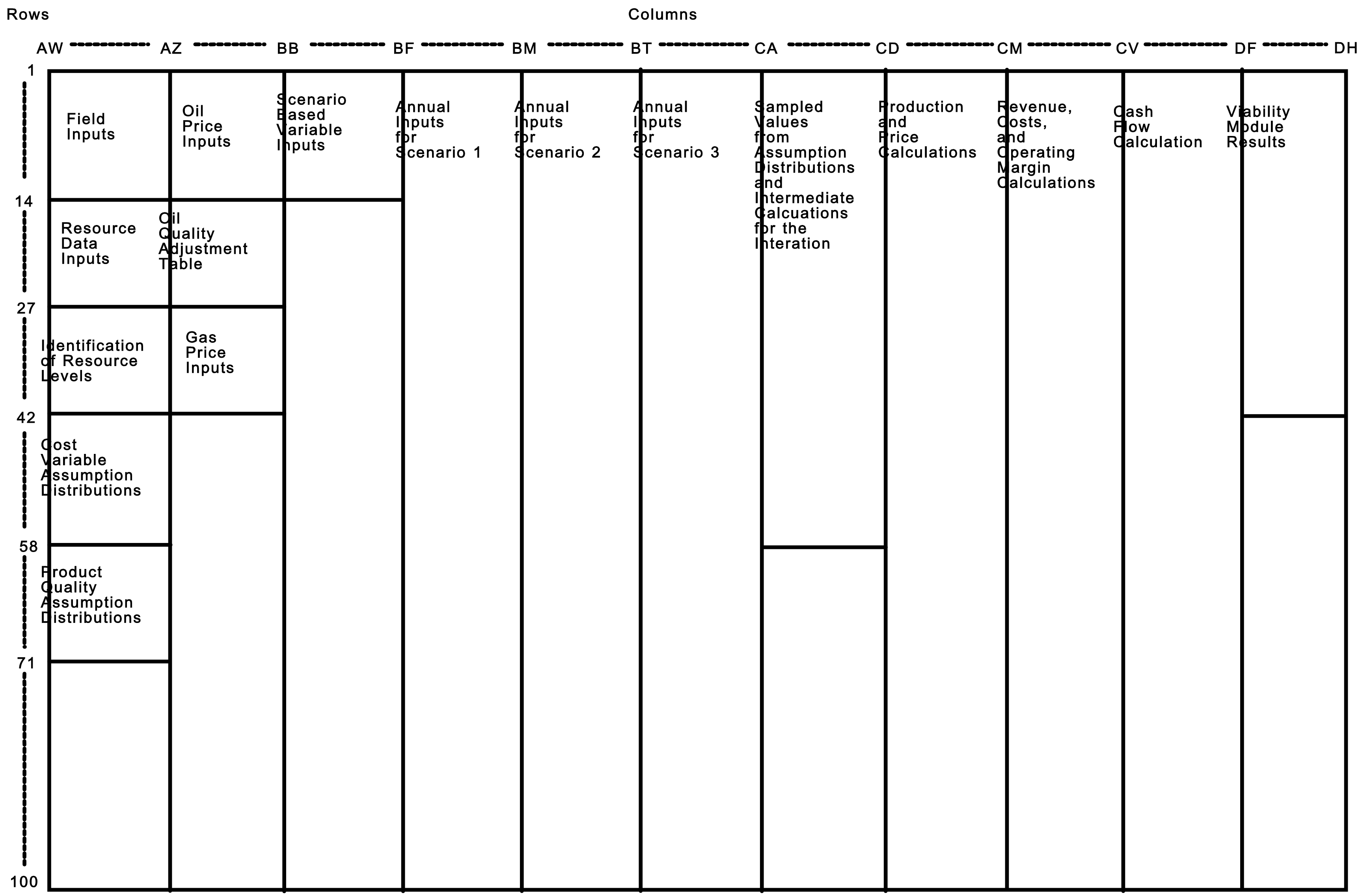
Resource Module Schematic

Columns

Rows 1 – 100

Columns	
D – F	Reservoir Names & Numbers
F – M	Probability Inputs - Risk, Probability All Oil, All Gas, Or Oil and Gas. Proportion of Oil and Gas if Both. Indicator if Reservoir Has Been Drilled Previously.
M – O	G O R Input Distributions
O – Q	Yield Input Distributions
Q – S	Acres Input Distributions
S – U	Net Pay Input Distributions
U – W	Oil Recovery Input Distributions
W – Y	Gas Recovery Distributions
Y – AC	Calculated Acre Feet of Oil & Associated Gas for Reservoirs that are all oil for titeration
AC – AF	Calculated Acre Feet of Gas & Condensate for Reservoirs that are all oil for iteration
AF – AM	Calculated Acre Feet of Oil & Associated Gas, Gas & Condensate for Reservoirs that are both oil and gas for titeration
AM – AT	Combined Totals of all Liquid Products (Oil & Condensates) Gaseous Products (Gas & Associated Gas) and BOE
AT – AV	Resource Module Field Level Results

Viability Module Schematic



UNITED STATES DEPARTMENT OF THE INTERIOR

MINERALS MANAGEMENT SERVICE

Appendix II to NTL No. 99-N04

GUIDELINES FOR THE APPLICATION,
REVIEW, APPROVAL, AND ADMINISTRATION OF
ROYALTY RELIEF FOR END-OF-LIFE LEASES

March 1999

TABLE OF CONTENTS

ATTACHMENTS

Recovery of Costs

Under Federal policy and statute, we'll charge you a fee for applying for royalty relief to recover our cost of processing your application. The Administrative Procedures Act (31 U.S.C. 9701) and Office of Management and Budget Circular A-25 require that we recover our costs when we provide services that confer special benefits or privileges to identifiable non-Federal recipients. Processing of applications for royalty relief clearly falls within this mandate.

The Omnibus Appropriations Bill (PL. 104-134, 110 Stat. 13221, April 26, 1996) authorizes our fees. The statute provides "That beginning in fiscal year 1996 and thereafter, fees for the royalty rate relief applications shall be established (and revised as needed) in Notices to Lessees, ... for the costs of administering the royalty rate relief authorized by 43 U.S.C. 1337(a) (3)."

We may issue a revised notice to lessees (NTL), updating NTL 98-5N, to provide more detailed information on the royalty relief application fees and when and how you make payments. Currently, we charge $8,000 to review your application and an additional $12,500 if we decide we need to audit your historical data to confirm that you qualify for relief. We will revise the NTL periodically to reflect our cost experience in administering this program.

OVERVIEW OF GUIDELINES
FOR END-OF-LIFE ROYALTY RELIEF UNDER 30 CFR PART 203

We issued final regulations (30 CFR Part 203) in January 1998 to implement the Outer Continental Shelf Deep Water Royalty Relief Act (Public Law 104-58 (DWRRA)). As part of that rule-making, we simplified and revised the way we implement authority the Secretary of the Interior has under 43 U.S.C. 1337(a)(3)(A) to reduce or eliminate royalties. This authority applies to oil and gas leases anywhere in the Federal Outer Continental Shelf (OCS). Leaseholders who have inadequate revenues to sustain production qualify for royalty relief if we determine that a modification in the royalty arrangement will result in recovery of additional resources.

Affected lessees may apply to the Minerals Management Service (MMS) for a reduced royalty rate by submitting the information specified under the final regulations. **The specific data, reports, and spreadsheets in an application are described in supplementary guidelines, issued as an attachment to this Notice to Lessees and Operators (NTL).** These supplementary guidelines also explain the procedures we will follow for evaluating applications and implementing royalty relief, and our rationale for excluding selected cost items from consideration.

We advise that you carefully review a copy of these guidelines if you intend to request End-of-Life Royalty Relief. They do not add any requirements to the regulations, but they will help you structure your application so as to expedite our evaluation. Be sure to use the most current version of these guidelines as we will periodically update them to reflect our experience in processing applications.

The NTL, the computer spreadsheet, and these guidelines are available from your regional office or on the MMS website at http://www.mms.gov.

Any collection of information that we mention in these guidelines provides clarification, description, or interpretation of requirements contained in 30 CFR Part 203. The Office of Management and Budget has approved our collection of information required by these regulations and assigned OMB Control Number 1010-0071. These guidelines do not impose additional information collection requirements that would be subject to the Paperwork Reduction Act of 1995.

Carolita U. Kallaur

Dated: March 5, 1999

Carolita U.Kallaur,
Associate Director for
Offshore Minerals Management

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Effective Date: March 5, 1999

Guidelines for the Application, Review, Approval, and Administration of Royalty Relief for End-of-Life Leases

A. Introduction

These guidelines interpret regulations (30 CFR Part 203.50 through 203.56 and 203.81 through 203.84) which establish the terms and conditions for granting reductions in royalty rates to end-of-life leases under the Outer Continental Shelf (OCS) Lands Act. This form of relief applies to Federal leases anywhere on the OCS that have meaningful levels of production. Other guidelines interpret regulations for deep water royalty relief.

As with the rule, we have written these guidelines in the "plain English" or conversational style. We (Minerals Management Service) instruct you (applicants, lessees, operators) on how to determine when you qualify for royalty relief and how you apply for it in a way that most efficiently facilitates our review. Also, we explain how we administer relief you may receive.

Guidelines are not strict rules like regulations, so we may deviate from individual elements of them if an applicant makes a convincing argument to do so. We will consider requests for departure from the guidelines only when an applicant provides compelling reasons for deviating from a provision before, or when submitting, a royalty relief application.

For purposes of royalty relief, designated unit operators may act as the applicant on behalf of all lessees (payors). Operators acting as applicants are responsible for assuring that the application contains accurate revenue, royalty, and transportation and processing allowance data on all sales from the lease. When not privy to all actual revenue, royalty and cost allowance data, operators must fully explain how they estimated those amounts and alert all payors that we may require such data and explanation from each one before we can make a final decision on an application.

B. Royalty Rate Reductions - General

Under 43 U.S.C. 1337 (a)(3)(A), we may reduce or eliminate the royalty or net profit share specified for your producing OCS lease to promote increased production. The purpose of royalty relief is to allow you reasonable financial returns so as to increase ultimate resource recovery (e.g., oil, gas, or sulphur) and augment receipts to the Federal Treasury. Therefore, we will modify the royalty rate where sound engineering and economic principles indicate that this change will extend the productive life of your lease.

We use only historic data to determine if you need end-of-life royalty relief. That reliance presumes that you continue to operate your lease in a way that does not significantly alter historical practice. We rely on certain procedures to protect the integrity of a decision based on historic data. If you have recently instituted or plan significant changes to your operation, you should implement such changes and operate for 12 months in your new configuration before seeking to qualify for royalty relief. Otherwise, we will defer action on your application until that circumstance is achieved. Until your application fully reflects the effect of recent significant changes to your operation, we cannot be confident that you need royalty relief to continue operations. We will wait up to 2 years for you to provide updated data reflective of your new configuration. Further, we will terminate your relief if you subsequently do things that we have notified you are significant changes to your operation.

C. Qualifications for Relief

Producing leases that have inadequate revenues to sustain continued production, i.e., end-of-life leases, can apply for royalty relief. The term "lease" refers to either a lease or an approved unit. To qualify for royalty relief, you need to show that your lease satisfies the following production and economic conditions.

1. To be eligible for royalty relief, the rule specifies that your lease must satisfy certain production requirements during a qualification period. By ***production***, we mean the sum of dispositions for oil and gas reported by the operator on MMS-4054 Form (OGOR-B report) to MMS. Under the rule, ***qualification months*** consist of the most recent 12 of the last 15 calendar-months in which you satisfy the following production requirements.

   For an oil and gas lease, the production requirement during a *qualifying month* is an average of at least 100 barrels of oil equivalent (BOE) per day. For a non-oil and gas lease, any positive level of production will satisfy the production requirement needed in a *qualifying month*.

   To allow for lags in data availability and you time to prepare an application, your 15 month period may end up to 120 days before the date we receive your certified application. Part of your application is an independent opinion from a certified public accountant (CPA). To expedite a CPA review, Attachment 3 outlines the confirmation procedures we believe are necessary for an independent opinion on the reliability of the data in your application.

2. To demonstrate that your lease is becoming uneconomic, the rule specifies that you must show that royalties you paid ***(ROY)*** exceed 75 percent of ***net revenues (NR)*** generated during your qualification months. The clearest way to show this is by substituting your data into the formulas below. Define ***Royalty Share*** (***RS***) as:

$$RS = \frac{ROY}{NR} (100\%) \qquad \text{where}$$

ROY is the net royalty that you have paid under the existing royalty arrangement, after determining royalty due and deducting any ***transportation and processing allowances*** (***TPA***) that you are permitted under regulations at 30 CFR 206 and recent precedents.

NR is your net revenues as defined by: ***NR = GVP - AC - TPC,*** where

Gross Value of Products (GVP) is gross proceeds all lease owners receive under arm's-length contracts for sale of production in marketable condition. Our Oil and Gas Payor Handbook, Volume III, Product Valuation gives details on how to compute this *GVP* as well as *TPA*.

In cases where a unit operator serves as the applicant on behalf of multiple payors, he must illustrate how he calculated *GVP*, *ROY*, and *TPA* on his part of sales. Integral to that illustration is a careful explanation of the basis for determining the amounts authorized by regulation at 30 CFR 206 and recent precedents. We will compare those amounts attributed to other payors on the lease from operator's calculation with what they actually reported to MMS. Where we find material discrepancies, we will request documented calculations from those payors.

Allowable Costs (AC) is a variable representing the sum of your expenses during the qualification months that are necessary for the continued operation of your lease. We follow the cost accounting structure prescribed for Net Profit Share Leases in 30 CFR 220.011 - 220.015 because it describes actual expenditures that benefit the on-going operation of your lease. Attachment 1 summarizes costs we consider allowable for end-of-life royalty relief qualification.

Generally, you may include expenses for operating and maintaining the existing wells and facilities on your lease and costs for replacement or side track wells completed in the same producing reservoir because these expenses are necessary for full recovery of the resources. With the exception of certain rentals described in Attachment 1, you may not include charges for recovering the capital cost of equipment or reserves (i.e., amortization, depreciation, depletion) because they are development costs not consistent with an end of life circumstance.

If you expend funds to place production in salable condition to obtain the *GVP* used for royalty calculation, you may include expenses for the requisite treatment activities (separation, dehydration, stabilization, etc.) that take place prior to the sales point. If these activities are carried out under an arm's-length contract with a nonaffiliated plant, allowable expenses equal the fees you pay for the treatment activities. Otherwise, we only allow fees in the amount that you can show reflect the actual costs incurred by the affiliated plant in treating your production. We follow the definition of affiliation (10 percent or more ownership) used in 30 CFR 206.101. Gas plant processing costs for activities designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration should be included in the transportation and processing allowance category described below.

You may also include reasonable portions of joint costs which rightfully should be allocated to this lease. Joint costs mean any of the cost items listed in Attachment 1 that benefit this lease and one or more other operations or leases. For instance, costs associated with producing reservoirs or part of reservoirs in State waters from a facility on a Federal lease are generally not allowable costs for Federal royalty relief purposes. However, if the State/Federal parts of the field are unitized, then we may allow the portion of unitized costs allocated to production from the Federal part of the lease. Because some joint costs may be difficult to allocate, we also allow you to assign a 5 percent overhead amount to certain cost items.

As the rule states, we may, in our review and evaluation of your application, disallow certain costs when we consider them to be unnecessary for the ongoing operation of your lease.

Transportation and Processing Costs (TPC) is a variable representing the sum of your reasonable, actual costs for transportation and processing associated with the oil and gas produced from your lease. *TPC* is based on the ***transportation and processing allowance (TPA)*** you are permitted under the regulations at 30 CFR 206 and recent precedents. You should illustrate and explain how you determined the *TPA* shown on the Report of Sales and Royalty Remittance (Form MMS-2014) you submitted during the qualifying period.

The ***TPA*** represents the part of your total *TPC* incurred to handle the lessor (royalty) share of the total product. Your *TPC* should never exceed your *TPA* divided by your royalty rate.

An example helps clarify the calculation for relief qualification.

Suppose *GVP* = 100, *AC* = 54, *TPA* = 2, and the effective royalty rate in the qualifying months is 1/3.

Then, *TPC* = 2 / (1/3) = 6;

ROY = (1/3) * (100 - 6) or = [(1/3) * 100] - 2 = 31.33; and

RS = [31.33/(100 - 54 - 6)] *100 percent = 78.3 percent

If your actual *TPC* is less than the amount calculated in this way, you should use the actual amount of your costs, with one exception. The exception is that in cases where you have approval of the MMS Royalty Management Program to report a tariff approved by the Federal Energy Regulatory Commission (FERC) in lieu of actual transportation costs, you may claim the part of the tariff associated with the royalty portion of production as the transportation allowance. However, for the remaining non-royalty portion of production, you must count only the reasonable actual costs, as opposed to any imputed costs or tariffs, incurred in transportation of the non-royalty portion of your production.

Processing costs can be claimed only for gas plant products, as defined in the regulations. The processing costs approved by the MMS Royalty Management Program can be claimed as part of the actual costs associated with the royalty portion of gas plant production. For the remaining non-royalty portion of the gas plant products, you must count only the actual costs, as opposed to any imputed costs, incurred in the processing of these products.

D. Form of Relief

Upon qualification, we will reduce the royalty rate to a fixed ***royalty relief rate*** of half of the lease's effective royalty rate, where the ***effective royalty rate*** represents the average royalty rate applied to the gross production volume during the 12 months included in the qualifying period. You may still claim the *TPA* credit against royalties owed after we grant relief.

If we have given relief to this lease before, the original lease rate may not be the same as the *effective royalty rate*. The following example illustrates how to find your *effective royalty rate* when more than one fixed rate has applied during the qualifying period.

Suppose that for 4 months production totals 500 (that is, averages 125/month) and one royalty rate (1/6) applies, and for the other 8 months production totals 2,000 while another royalty rate (1/3) applies.

The production-weighted average royalty rate over the qualifying period or the *effective royalty rate* is {[(500 * (1/6)) + (2,000 * (1/3))]/(500 + 2,000)} * 100 percent = 30 percent, so the *royalty relief rate* would be 15 percent.

If you operated under a net revenue share royalty system, you must derive an *effective royalty rate* for each month by dividing royalties owed by well-head value (*GVP* - *TPC*). The following example illustrates how to find your *effective royalty rate* for one month when your royalty was determined by a net revenue or net profit share system.

Suppose your monthly royalty obligation is 50 percent of *GVP* (of say 3,000) less *TPC* (of say 700) and less an allowable operating cost (of say 920).

Your *effective royalty rate* for the month is {[(0.5 * (3,000 - 700 - 920))]/(3,000 - 700} * 100 percent = 30 percent

The calculation must be repeated for each of the 12 qualifying months and the result for each month weighted by the production volume in the same month. If the production-weighted average of your *effective royalty rates* in all 12 qualifying months worked out to be 30 percent, your *royalty relief rate* would again be 15 percent.

The royalty relief rate will apply to production up to the ***royalty relief volume***. It is equal to the monthly average number of barrels of oil equivalent produced over the 12 months in the qualification period. For natural gas production, 5,620 cubic feet of gas is equivalent to one barrel of oil.

With the production numbers from the above example, the *royalty relief volume* would be (500 + 2,000)/12 = 208.3.

Any monthly volume of production above and up to 2 times the *royalty relief volume* will bear royalties at 1.5 times the effective royalty rate. Production above 2 times the relief volume amount pays the effective royalty rate. The following illustration continues the example.

Suppose production reaches 300 in a month after relief is granted.

You would owe royalties on the first 208.3 at a 15 percent rate, while you would owe royalties on the remaining 91.7 at a 45 percent rate (1.5 * 30 percent).

You should compute an average royalty rate each month, which serves as the rate for calculating actual royalties due. You find it by taking the production-weighted average of the rate associated with production up to the relief volume (equal to ½ the *effective royalty rate*), and the rate associated with additional production (equal to 1.5 times the *effective royalty rate* for up to double the *royalty relief volume* and the effective royalty rate for any greater volume). The following illustration completes the example.

The average royalty rate for a month with production of 300 is {[(208.3 * 0.15) + (91.7 * 0.45)]/300} * 100 percent = 24.17 percent.

If production climbs to 420, the average royalty rate is {[(208.3 * 0.15) + (208.3 * 0.45) + (3.4 * 0.3)]} * 100 percent = 30 percent. In effect, the average *relief royalty rate* gradually increases (as monthly production) rises to a cap at the pre-relief *effective royalty rate*.

E. Suspension of Relief

You owe royalties at the *effective royalty rate* on all production during any month in which sweet crude oil and natural gas prices increase by more than 25 percent. You should calculate the increase as the difference between the current weighted 12 calendar-month rolling average of NYMEX (New York Mercantile Exchange) and the weighted 12 calendar-month average of NYMEX prices during your qualification months. The weighting factors for oil and gas are the percentages of your total production provided by each product during the 12 qualifying months. In these cases, the *effective royalty rate* will apply to all your production.

Suppose you produced an average of 3,500 bbls of oil and 2,810 mcf of gas (with 1.1 MMbtu per mcf) per month during your 12 qualifying months. Converting gas to BOE using a factor of 5,620 scf/bbl, your production weighting factors are {3,500/[(3,500 + (2,810/5.62)]} * 100 percent = 87.5 percent oil and 12.5 percent gas.

Suppose over your 12 qualifying months average NYMEX oil prices were $12/bbl and average NYMEX gas prices were $2 per million Btu. Your base price level is ($12 * 0.875) + [(2 * 1.1) * 0.125] = $10.775/BOE. If average NYMEX prices weighted by these factors exceed ($10.775 * 1.25) = $13.47/BOE, you would owe royalties at your pre-relief or effective rate. This happens if the average NYMEX oil price rises to $15/bbl and the average NYMEX gas price rises to $2.50/MMBtu over the same 12 month period. It also would happen if the average NYMEX oil price rose to $15.08/bbl and gas prices remained at $2/MMBtu.

F. Termination of Relief

End-of-Life royalty relief ends in any of three situations.

1. At any time you may renounce, by written notification to the MMS Regional Director for your area, the royalty relief granted under these guidelines. After we acknowledge the change, you will owe royalties at the pre-relief or effective rate as of the next full month when royalties are due.

2. Relief ends when your average royalty rate equals the effective rate for 12 consecutive months. This would happen if prices remain more than 25 percent above their average level in your qualifying months or if your production is double or more the relief volume for 12 consecutive months.

3. We reserve the right in individual cases to specify activities that will end relief because they are not compatible with an end-of-life circumstance. If we choose to reserve this right in your individual case, we will notify you in our letter approving your end-of-life relief what activities are incompatible with continuation of relief and when relief would terminate. Also, we will indicate the terms to which your royalty obligation will revert in the event such activities occur.

G. Withdrawal of Relief

If we find that you provided false or intentionally inaccurate information that was material to our granting you relief, you must pay full royalties and late payment interest determined under 30 U.S.C. 1721 on all production on which you used the royalty relief. You may also be subject to penalties under other provisions of law.

H. Review And Audit

All data you submit in support of the relief application is subject to review and audit.

I. Procedures for Submitting Applications

You should file your application for royalty relief with the MMS Regional Director for your area. Under the rule, your application must contain two reports: (1) Administrative Information; and (2) Net Revenue and Relief Justification. Attachment 2 describes what should be in these reports.

Attachment 3 outlines procedures for an acceptable CPA certification. Attachment 4 illustrates a spreadsheet format you should use in the Net Revenue and Relief Justification Report.

Ordinarily we would not expect the operator and owners who file an application for royalty relief to change while we are evaluating the application. To preserve the integrity of a pending application, we insist that the designated operator remain unchanged until we render a relief decision. However, owners may change during our evaluation period without affecting a pending application. After we have rendered a relief decision, operators as well as owners are free to change without affecting relief we have already granted.

Before you can reapply either for relief after your previously held relief has ended, or for more relief, the rule holds that your lease must have 12 qualifying months under the same royalty or relief terms. When you have had the same royalty terms for 12 qualifying months, you still have to pass the qualifications listed in Section C above.

J. Procedures for Review, Evaluation, And Decision

We will review the royalty relief application for completeness and verify that the data are reasonable. If we determine that you do indeed meet the qualification requirements, then we'll give you royalty relief because it should induce meaningful quantities of incremental production. We will notify you in writing of the *royalty relief volume* amount, the *effective royalty rate*, the threshold average oil and gas price level at which suspension and possible termination of relief occur (for an oil and gas lease), other conditions or clarifications of the arrangement, and the date on which the new terms would begin. Your new arrangement normally would start on the first day of the month following the date we approve your relief.

If your application is incomplete or we decide your data are not reasonable, we will give you the opportunity to submit additional or revised information. If your response cannot clear up our concerns, we will deny your request for royalty relief. If we deny your request, we will explain our decision and rationale to you in writing. We retain the application fee. You may appeal any of our decisions to the Director, MMS, within 30 days, under the provisions of 30 CFR 290.

Attachment 1
Allowable Cost Categories Associated with the Cost Variables Used to Determine Qualification for Royalty Relief

The text of these guidelines refers to several different cost variables we use to determine your qualification for royalty relief. Each of these variables consist of expenditures associated with several different cost categories. This attachment summarizes categories of allowable cost, drawn from 30 CFR 220.011, and describes what expenditures we view as eligible costs in the respective cost categories. Our companion guidelines on deep water royalty relief includes an almost identical attachment (Attachment C) on allowable costs. *Italics* in this Attachment 1 denote passages which deviate from Attachment C in the other guidelines.

Table 1 - Cost Codes and Categories

Cost Code	Cost Category
100	Labor
200	Material
300	Transportation
400	Contract Services
500	Lessee Owned Rentals
600	Insurance
700	Communications
800	Ecological and Environmental
900	Abandonment
1000	Other Costs
1100	Other Credits

Many of the allowable cost definitions we use for royalty relief are the same as those we allow for Net Profit Share Leases (NPSL). Where the definition of terms is identical, we refer to the corresponding cite in the Code of Federal Regulations. In those instances where the definitions differ, we specify the definition appropriate for royalty relief purposes.

Costs associated with Labor, Material, Abandonment and Other Costs categories are eligible for an overhead allowance of 5 percent, slightly more generous than the share allowed during the relief period in the NPSL regulations at 30 CFR 220.012. Other categories tend to be contract costs which already have an overhead included in them. Joint costs and credits should be allocated to the lease in the same manner as described in the NPSL regulations at 30 CFR 220.014.

There are two basic rules you should follow when making decisions on whether to include particular costs in the application. First, we count and you should submit only costs or portions of costs that you can validate as necessary for the proper conduct of your lease operations.

Second, we don't allow and you should not submit costs for any obligation that *you incurred before the qualifying period. For example, we don't allow amortization or depreciation charges for equipment or facilities you acquired before the qualifying months. You incurred such capital costs because you anticipated being able to recover them without royalty relief.* Likewise we don't allow the costs incurred for the abandonment of pre-existing wells and facilities. These obligations remain regardless of the economic performance of your lease, so they are not relevant to whether you continue to produce on an otherwise profitable lease.

A. Labor (cost code 100) covers:

1. Salaries and wages of field employees, first level supervisors, and technical employees employed in the operation of your lease, in the area of your lease.

2. Salaries and wages of technical employees within technical branches of your organization that may not work in the area of the lease but are working "full time" on some particular technical problem or operations aspect of your lease. Excluded from this category are employees assigned a role in your lease's operations as a duty collateral with other duties that do not directly benefit that lease.

3. Salaries and wages of technical employees within technical branches of your organization who are assigned technical tasks directly related to the operation of your lease provided they are supported by adequate time records showing the nature of the task and the hours spent on the task.

4. Employee benefits allowable according to 30 CFR 220.011(b)(2-6).

5. Overhead allowance up to 5 percent of the sum of the other costs in this category. This, together with the corresponding amounts in items B, I, and J, below is designed to cover your finance, administration, and management activities appropriate for the lease.

B. Material (cost code 200) covers items you purchase or furnish as lease property. We look for the following attributes in costs you claim in this category.

1. You charge or credit material at amounts specified in 30 CFR 220.015. Your purchase and inventorying of material conforms to the conditions and provisions of 30 CFR 220.032.

2. You charge to the lease only such material purchased or furnished as lease property that is consistent with efficient and economical operations. You have not accumulated surplus stocks.

3. You credit to your lease costs for salvaged or returned material.

4. Overhead allowance up to 5 percent of the sum of the other costs in this category.

C. Transportation (cost code 300) covers charges for transportation of employees and material necessary for your lease operations to, from and within the lease area. We look for the following attributes in transportation charges you claim.

1. You only charge transportation costs for material for a distance not greater than the distance from where like material is normally available.

2. You count transportation charges for material shipped from the lease only for lease material and then only to the nearest reliable supply store, barge terminal, or railway receiving point.

3. You do not include expenditures under $200 in transportation charges for material.

D. Contract Services (cost code 400) covers the cost of services and utilities provided to your lease under contract by outside parties and rental charges paid to outside parties for the use of equipment in the lease area in support of lease operations. These services must be provided under an arm's-length contract as defined in 30 CFR 206. Actual costs, rather than fees, for services provided under a non-arm's-length contract must be included in the following cost categories. We look for the following attributes in the costs you claim for contract services.

1. The contract services constitute proper and necessary lease operations or support for lease operations.

2. You charge the contract rate for contract services (including consulting services or contracted technical personnel) established exclusively for the lease.

3. You allocate the cost of contracted services shared among this lease and others pro-rata to the applicable leases.

4. You do not count the costs of contract services for research and development.

E. Rental of Equipment and Facilities Furnished by Lease Owner(s) or affiliated parties (cost code 500) covers the use of equipment and facilities which you acquire *during the qualifying months* that are proper and necessary for lease operations and are not lease property.

1. These may include shore base and offshore facilities, and pipelines from the lease to shore based facilities.

2. The methodology for determining allowable charges for the use of non-lease equipment furnished by the lessee is specified at 30 CFR 220.011(g).

F. Insurance (cost code 600) covers net premiums you pay for insurance you are required to carry for lease operations.

G. Communications (cost code 700) cover the costs of leasing, acquiring, installing, operating, repairing, and maintaining communication systems, including radio, microwave facilities, and computer production controls for lease operations according to the proportion of those costs that are allocable to lease operations.

H. Ecological and Environmental (cost code 800) cover three items.

1. Those costs you incur in the lease area as a result of statutory regulations for archeological and geophysical surveys relative to the identification and protection of cultural resources.

2. Your cost to provide or to have made available pollution containment or removal equipment, including payments to organizations or funds which supply equipment or assistance in the event of oil spills or other environmental damage.

3. Your costs for the actual control and cleanup of oil spills and resulting responsibilities required by applicable laws and regulations except in cases of your negligence or willful misconduct. We don't allow any costs from an incident resulting in civil or criminal penalties.

I. Abandonment (cost code 900) covers three items.

   1. We allow costs associated with abandonment of wells *you drilled during the qualification period* but not costs associated with wells existing before *the start of the qualification period*.

   2. We allow costs associated with abandonment of a well bore for the purpose of using it to drill into *a producing* reservoir included in the project and with modification of platform equipment for project specific purposes.
   3. Overhead allowance up to 5 percent of the sum of the other costs in this category.

J. Other Costs (cost code 1000) covers costs not included above that you incur in the necessary and proper conduct of the lease operation. You should have any costs in this category specifically approved by the Director, MMS, or appropriate delegated authority. You may include an overhead allowance of up to a 5 percent of the other costs in this category.

K. Other Credits (cost code 1100) cover credits to lease operations for:

   1. Lease property you lease to or use in non-lease operations,

   2. Your sale of information derived from test wells and geological and geophysical surveys, and

3. For any and all amounts earned or otherwise due you as a result of lease operations.

In addition to those costs listed at 30 CFR 220.013, the following costs are not allowable:

1. OCS rental payments on the lease(s) in the application.

2. Damages and losses.

3. Taxes.

4. Any costs associated with activities that are exploratory in nature.

5. Civil or criminal fines or penalties.

6. Royalty relief application fees.

7. Costs associated with prior existing obligations (e.g., royalty overrides or other forms of payment for acquiring a financial position in a lease).

Attachment 2
Reports Required for a Complete Application

The rule specifies that your application must include the following information.

1. **Administrative Information Report** - You use this report to identify your lease or unit and to summarize its background. It includes:

   - Serial number and block designation of your lease, names of the titleholder of record, the lease operator, the identification of whether the lease is part of a unit and description of lease or unit history.

   - Company designation, the API number, location and status of each well that has been drilled on the lease.

   - Full information as to whether you are obligated to pay royalties or payment out of production to anyone other than the United States, the amount to be paid, and your efforts to reduce them.

2. **Net Revenue and Relief Justification Report** - You use this report to summarize your lease or unit's production, revenue and cost history for your qualifying months.

- It consists of a cash flow statement with the following items for each of 12 qualifying months (i.e., those most recent 12 of the last 15 months which had production of at least 100 barrels of oil equivalent per day). Attachment 4 illustrates the spreadsheet format we recommend that you use for your cash flow statement.

   1. All lease production subject to royalty computed in accordance with the lease and applicable regulations.
   2. Total revenues received on all lease production.
   3. Total royalties paid on all lease production.
   4. Allowable costs (using the cost categories identified in Attachment 1).
   5. Total transportation and processing costs allowed under MMS regulations.
   6. Calculation of net income and revenue share.

- The spreadsheet should demonstrate that royalties paid exceed 75 percent of net revenues generated during the qualifying months.

- You must have this report certified by an independent certified public accountant (CPA) expressing any specific reservations or the lack of any reservations about the accuracy of the historical financial information and that the presentation and interpretation of the data elements conform to the MMS guidelines. Attachment 3 describes the essential elements of this CPA certification.

- You should carefully explain any significant variability within a cost variable or category.

Attachment 3
Procedures For Streamlining CPA Certification

The purpose of CPA certification is for an independent expert to confirm that only allowable operating, transportation, and processing costs are used for qualification. Three steps are critical: (1) separating charges incurred on the subject lease(s) from ones incurred elsewhere; (2) identifying and eliminating any charges not allowed under MMS regulations and guidelines; and (3) dividing the remaining operating charges into two parts, those authorized to claim a 5 percent overhead and those not authorized to claim overhead.

The applicant's own accounting system may not match that described in Attachment 1 of the MMS end-of-life Guidelines. When that is the case, the following procedural checks should suffice to certify accuracy of historical financial information and conformity to MMS guidelines.

1. To confirm applicability and accuracy of costs, identify and list other audits performed for the qualifying period used in the application that contain these lease(s) and associated facilities.
   a. If one or more other audits have been performed, review cost structure provided in the application to be sure it is consistent with costs for the application lease(s) shown in the other audits. Identify any inconsistencies.
   b. If no other audits have been performed for the qualifying period, audit a random sample of sub-ledger records for charges assigned to the lease(s). Check invoices for any unusually large or erratic items (e.g., $2 million, or double previous month's level).

2. To confirm inclusion of only allowable costs, determine which categories in the applicant's own accounting system are likely to record charges not allowed under MMS regulations and guidelines (30 CFR 220.013 and Attachment 1 of end-of-life guidelines).
   a. Review cost elements in these categories of the applicant's own accounting system which should record any non-allowed costs. Eliminate charges for any items found to be non-allowable from the amount confirmed in procedure 1 above.
   b. Compare any transportation and processing costs shown in the application with transportation and processing allowances claimed against past royalty payment obligations. Certify that the two figures are consistent.

3. To confirm that only authorized overhead is claimed, allocate cost categories from the applicant's accounting system either to those authorized to charge overhead (labor, material, abandonment, or other as described in Attachment 1) or to those not allowed to (contract services, transportation, rentals, insurance, communications, ecological and environmental). Either of two options may be used to check the size of the overhead subset of allowed costs.
   a. If a majority (>50 percent) of charges in an applicant's cost category fall into MMS categories that are authorized overhead, the whole category of costs is allocated to the

overhead subset, otherwise the whole category of costs is allocated to the non-overhead subset.

b. In each category of the applicant’s accounting system, charges authorized overhead may be identified and combined with like charges in the other categories of the applicant’s accounting system.

Attachment 4

Spreadsheet Format for Production, Revenue and Cost Data

We urge you to report your data in the format shown on this and the next two pages. You may get a computer (Excel) version of this spreadsheet, which includes formulas to preform the appropriate calculations, from your Regional MMS Director or MMS website at http://www.mms.gov.

Zeros or "ROY/NR" in the following spreadsheet tables indicate cells where formulas calculate values based on entries in the blank cells. Entries in the "Month/Year" column are simply illustrations to be replaced by the qualification period relevant to your application.

End-of-Life Royalty Relief

Relief Qualification Worksheet (page 1)

Month/Year	Royalties Paid (ROY)	Gross Value of Production (GVP)	Allowable Costs (AC)	Transportation & Processing Costs (TPC)	Net Revenue (NR) (GVP - AC - TPC)	Royalty Share
Jan-98	$0.00	$0	$0	$0	$0	ROY/NR
Feb-98	$0.00	$0	$0	$0	$0	ROY/NR
Mar-98	$0.00	$0	$0	$0	$0	ROY/NR
Apr-98	$0.00	$0	$0	$0	$0	ROY/NR
May-98	$0.00	$0	$0	$0	$0	ROY/NR
Jun-98	$0.00	$0	$0	$0	$0	ROY/NR
Jul-98	$0.00	$0	$0	$0	$0	ROY/NR
Aug-98	$0.00	$0	$0	$0	$0	ROY/NR
Sep-98	$0.00	$0	$0	$0	$0	ROY/NR
Oct-98	$0.00	$0	$0	$0	$0	ROY/NR
Nov-98	$0.00	$0	$0	$0	$0	ROY/NR
Dec-98	$0.00	$0	$0	$0	$0	ROY/NR
12 month total/average	$0	$0	$0	$0	$0	ROY/NR

End-of-Life Royalty Relief

Production/Royalty Summary - All Products by Month/Year (page 2)

Product	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98
Oil												
Sales Volume												
Sales Value												
Transportation												
Royalties Paid												
Gas												
Sales Volume												
Sales Value												
Transportation												
Royalties Paid												
NGL												
Sales Volume												
Sales Value												
Transportation												
Processing												
Total T&P	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Royalties Paid												
Other Products												
Sales Value												
Total T&P												
Royalties Paid												
All Products												
Sales Value	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Total T&P	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Royalties Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

End-of-Life Royalty Relief

Allowable Costs (page 3)

Code	Category	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98
100	Labor												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
200	Material												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
300	Transportation												
400	Contract Services												
500	Lessee Owned												
	Rentals												
600	Insurance												
700	Communications												
800	Ecological &												
	Environmental												
900	Abandonment												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1000	Other Costs												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1100	Other Credits												
	Total Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0