accounting activities are performed, at the print shop located in the zone. K, on occasion, uses its equipment (including its trucks) and employees to deliver large print jobs to customers who reside outside of the zone. So long as K is able to establish that its trucks are used in the zone at least 85% of the time and its employees perform at least 85% of services for K in the zone, K meets the requirements of sections 1397B(b)(3) and (5).

Example 5. Treatment as a separately incorporated business. The facts are the same as in *Example 4* except that six years after the issue date of the enterprise zone facility bonds, K determines to expand its operations to a second location outside of the boundaries of the zone. Although the expansion would result in the failure of K to meet the tests of 1397B(b), K, using a reasonable allocation method, allocates income and activities to its operations within the zone and has evidence of these allocations sufficient to establish compliance with the requirements of paragraphs (b) through (f) of this section. The bonds will not fail to be enterprise zone facility bonds merely because of the expansion.

Example 6. Treatment of pooled financing bond programs. Authority L issues bonds in the aggregate principal amount of $5,000,000 and loans the proceeds to Bank M pursuant to a loans-to-lenders program. M does not meet the definition of enterprise zone business contained in section 1397B. Prior to the issue date of the bonds, L held a public hearing regarding issuance of the bonds for the loans-to-lenders program, describing the projects of identified borrowers to be financed initially with $4,000,000 of the proceeds of the bonds. The applicable elected representative of L approved issuance of the bonds subsequent to the public hearing. The loan agreement between L and M provides that the other proceeds of the bonds will be held by M and loaned to borrowers that qualify as enterprise zone businesses, following a public hearing and approval by the applicable elected representative of L of each loan by M to an enterprise zone business. None of the loans will be in principal amounts in excess of $3,000,000. The loans by M will otherwise meet the requirements of section 1394. The bonds will be enterprise zone facility bonds.

Example 7. Original use requirement for purposes of qualified zone property. City N issues enterprise zone facility bonds, the proceeds of which are loaned to Corporation P to finance the acquisition of equipment. P uses the proceeds after the zone designation date to purchase used equipment located outside of the zone and places the equipment in service at its location in the zone. Substantially all of the use of the equipment is in the zone and is in the active conduct of a qualified business by P. The equipment is treated as qualified enterprise zone property under section 1397C because P makes the first use of the property within the zone after the zone designation date.

Example 8. Principal user. State R issues enterprise zone facility bonds and loans the proceeds to Partnership S to finance the construction of a small shopping center to be located in a zone. S is in the business of commercial real estate. S is not an enterprise zone business, but has secured one anchor lessee, Corporation T, for the shopping center. T would qualify as an enterprise zone business. S will derive 60% of its gross rental income of the shopping center from T. S does not anticipate that the remaining rental income will come from enterprise zone businesses. T will occupy 60% of the total rentable space in the shopping center. S can use enterprise zone facility bond proceeds to finance the portion of the costs of the shopping center allocable to T (60%) because T is treated as the principal user of the enterprise zone facility bond proceeds.

Example 9. Remedial actions. State W issues pooled financing enterprise zone facility bonds, the proceeds of which will be loaned to several enterprise zone businesses in the two enterprise communities and one empowerment zone in W. Proceeds of the pooled financing bonds are loaned to Corporation X, an enterprise zone business, for a term of 10 years. Six years after the date of the loan, X expands its operations beyond the empowerment zone and is no longer able to meet the requirements of section 1394. X does not reasonably expect to be able to cure the noncompliance. The loan documents provide that X must prepay its loan in the event of noncompliance. W does not expect to be able to reloan the prepayment by X within six months of noncompliance. X's noncompliance will not affect the qualification of the pooled financing bonds as enterprise zone facility bonds if W uses the proceeds from the loan prepayment to redeem outstanding enterprise zone facility bonds within six months of noncompliance in an amount comparable to the outstanding amount of the loan immediately prior to prepayment. X will be denied an interest expense deduction for the interest accruing from the first day of the taxable year in which the noncompliance began.

(q) *Effective dates*—(1) *In general.* Except as otherwise provided in this section, the provisions of this section apply to all issues issued after July 30, 1996, and subject to section 1394.

(2) *Elective retroactive application in whole.* An issuer may apply the provisions of this section in whole, but not in part, to any issue that is outstanding on July 30, 1996, and is subject to section 1394.

Approved: May 22, 1996.

Margaret Milner Richardson,

Commissioner of Internal Revenue.

Leslie Samuels,

Assistant Secretary of the Treasury.

[FR Doc. 96–13718 Filed 5–30–96; 8:45 am]

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DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 203

RIN 1010–AC13

Royalty Relief for Producing Leases and Certain Existing Leases in Deep Water

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Interim Rule and Information Gathering.

SUMMARY: This interim rule establishes conditions for granting royalty relief on producing leases through their conversion to Net Revenue Share (NRS) leases, provides for suspensions of royalty payments on certain deep-water leases issued as the result of a lease sale held before November 28, 1995, and defines the information required for a complete application for royalty relief.

DATES: This interim rule is effective July 1, 1996.

We will consider all comments we receive by July 30, 1996. We will begin review of comments at that time and may not fully consider comments we receive after July 30, 1996.

ADDRESSES: Mail or hand-carry comments to the Department of the Interior; Minerals Management Service; Mail Stop 4700; 381 Elden Street; Herndon, Virginia 22070–4817; Attention: Chief, Engineering and Standards Branch.

FOR FURTHER INFORMATION CONTACT: Dr. Marshall Rose, Economic Evaluation Branch, telephone (703) 787–1536.

SUPPLEMENTARY INFORMATION:

I. Objectives of Royalty Relief

Royalty relief can lead to increased production of natural gas and oil, creating profits for lessees and royalty and tax revenues for the government. By this rulemaking, the Secretary seeks to establish economic incentives to encourage Outer Continental Shelf (OCS) lessees to incur the expenses or make the capital investments necessary to maintain or increase production. To the extent possible for approved applications, we will reduce or suspend royalty payments to permit lessees to earn a reasonable return on their capital investment for projects involving new investment. For projects not involving new investment, we will provide relief sufficient to allow an operating profit in cases where expenses plus royalties exceed revenues.

The Secretary will implement these royalty relief provisions in conjunction with his stewardship responsibilities for the 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.

II. Legislative Background

The Secretary has broad legislative authority to reduce royalty rates on OCS leases. The Outer Continental Shelf Lands Act (OCSLA), as amended, (43 U.S.C. 1337(a)(3)(A)) states:

''The Secretary may, in order to promote increased production on the lease area, through direct, secondary, or tertiary recovery means, reduce or eliminate any royalty or net profit share set forth in the lease for such area.''

This provision gives the Secretary authority to reduce royalties on producing leases upon application by a lessee. Leases may be in shallow or deep water and may be located in any area of the OCS. Relief must be applied for, justified, and granted on a case-by-case basis.

On November 28, 1995, President Clinton signed Public Law 104–58, which included the Deep Water Royalty Relief Act (DWRRA). Section 302 of the DWRRA amends the OCSLA authority to allow the Secretary to grant relief on both producing and nonproducing leases and on categories of leases, rather than only on a case-by-case basis, in order to promote development, increase production, or encourage marginal production on Gulf of Mexico leases lying west of 87 degrees, 30 minutes West longitude. This rulemaking does not include regulations to implement the expanded discretionary authority to grant royalty relief in 43 U.S.C. 1337(a)(3)(B). Regulations for that purpose may be included in a future rulemaking.

In addition, the DWRRA also contains three other major provisions related to leases issued as a result of sales held before and after the date of the DWRRA's enactment.

First, section 303 establishes a new bidding system that allows the Secretary to offer tracts with royalty suspensions for a period, volume, or value of production. On February 2, 1996, we published a final rule modifying the regulations for the bidding systems we use to offer OCS tracts for lease (61 FR 3800). Portions of that rule in 30 CFR 260.110(a)(7) address the new bidding system authorized by section 303 of the DWRRA.

Second, section 304 mandates that all tracts offered within 5 years of the date of enactment in water depths of 200 meters or more in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude, must be offered under the new bidding system permitted by section 303. The Secretary must offer such tracts with a specified minimum royalty suspension volume based on water depth. We published an interim rule in the Federal Register on March 25, 1996 (61 FR 12022), specifying the terms under which the Secretary will make royalty suspensions available for new deep-water leases issued as the result of sales held after November 28, 1995.

Third, again in section 302, the DWRRA provides that ''new production,'' as defined in that Act, from a lease or unit in existence on the date of its enactment, and in water depths of 200 meters or greater in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude, does not qualify for royalty suspensions if the Secretary determines that the new production would be economic in the absence of royalty relief. Otherwise, the Secretary must determine the volume of production on which no royalty would be due in order to make the new production economically viable. This determination must be made on a case-by-case basis.

For existing leases or units which had no royalty bearing production, other than test production, before November 28, 1995, and which qualify for relief under section 302, the following minimum volumes of production are not subject to the royalty obligation specified in the lease:

- 17.5 million barrels of oil equivalent (MMBOE) for leases in 200 to 400 meters of water,
- 52.5 MMBOE for leases in 400 to 800 meters of water, and
- 87.5 MMBOE for leases in more than 800 meters of water.

These leases may qualify for a larger suspension volume if they would not be economic at the minimum royalty suspension volume specified by the DWRRA.

We also may grant a royalty suspension volume for production resulting from lease development activities pursuant to a Development Operations Coordination Document (DOCD), or a supplement to an approved DOCD, approved by the Secretary after November 28, 1995, that would expand production significantly beyond the level anticipated in a prior DOCD. In this case, we will grant the royalty suspension volume that we determine to be necessary to make the new production from the proposed project economic.

III. The Need for an Interim Rule

The DWRRA requires the Secretary to issue implementing regulations within 180 days of enactment. We cannot conduct and complete the usual proposed notice and comment rulemaking process to implement this part of the DWRRA before the statutorily imposed May 28, 1996, deadline. However, because the public interest would be best served by meeting the deadline and by establishing rules for these provisions of the DWRRA as soon as practicable, we are issuing this interim rule.

Several factors, in combination, have prevented us from issuing comprehensive rules through the usual rulemaking process by the statutory deadline. The Department of the Interior was shut down from December 12, 1995, to January 8, 1996, due to the lack of funding. Subsequently, MMS offices in the Washington, DC area were closed again for several days because of the ''blizzard of '96.''

These closings consumed critical time that would have been used to conduct the planning and preparation necessary to define the issues involved and devise an orderly process for a comprehensive rulemaking that would allow for as much advance notice and meaningful public participation as possible within the statutory deadline. Because of the complexity of the issues involved in this rulemaking, we believe the public interest would not be served by severely abbreviating the notice and comment procedures of the rulemaking process to meet the May 28, 1996, deadline.

Therefore, we decided the public interest would be served best by instituting a multipart rulemaking to meet the statutory objectives and allow extensive and meaningful public participation, consistent with law.

As the first step, we promptly published an Advance Notice of Proposed Rulemaking (ANPR) in the Federal Register on February 23, 1996 (61 FR 6958), and announced our intent to develop comprehensive regulations implementing the DWRRA. The ANPR sought comments and recommendations to assist us in that process. The comment period did not close until April 8, 1996, leaving too little time for a meaningful proposed notice and comment rulemaking by May 28, 1996. We also conducted a public meeting in New Orleans on March 12 and 13, 1996, to discuss with interested members of the public the matters the ANPR addressed.

We published an interim rule in the Federal Register on March 25, 1996 (61 FR 12022), specifying the terms under which we will make royalty suspensions available for new deep-water leases issued as a result of sales held after November 28, 1995.

As in the case of the interim rule for royalty suspensions for new deep-water leases, implementation of the DWRRA's provisions for existing leases by the Congressionally prescribed deadline is in the public interest. These provisions should be implemented promptly so that lessees may proceed with important investment decisions. Furthermore, as explained below, failure to issue implementing regulations by the prescribed deadline would create a legal uncertainty under which we might be required to grant royalty relief to one or more OCS projects that would not otherwise qualify. In that situation, there would be potential losses of hundreds of millions of dollars in Federal revenues.

The availability of royalty suspensions for new production from existing deep-water leases becomes an important factor in lessees' decisions about whether or not to proceed with development of oil and gas on their leases. However, lessees cannot adequately consider or accurately plan the potential economic benefits of royalty relief until we issue regulations establishing the procedures for granting a royalty suspension and defining the data and information required for a complete application. Respondents to the ANPR indicated their desire to have us make this information available to them as soon as possible.

Lessees are likely, therefore, to delay investment decisions until we have implementing regulations in place. These investments are important to the national and regional economies and any delay could adversely impact very important economic activity. Thus, it is in the public interest to proceed to issue an interim rule within the time frame mandated by Congress.

The establishment of interim regulations is also necessary so that lessees can make informed decisions about whether to proceed with lease development activities or allow their leases to expire. Our regulations (30 CFR 250.13) provide that lessees must engage in drilling, production or well-reworking activities in order to keep their leases in force beyond the primary term specified in the lease. If they do not, then in the absence of production after the primary term of the lease, their leases expire at the end of the primary term or 90 days after drilling activities cease.

Of the approximately 1,600 leases in deep water in the Central and Western Gulf of Mexico, 116 leases are nearing the end of their primary term. Lessees, aware that Congress was considering the enactment of royalty relief legislation, may have deferred taking action on their leases so they could properly account for such relief in calculating project economics.

However, lessees cannot make the necessary calculations until we issue implementing regulations. If we were to go through the usual rulemaking process, some leases could reach their expiration date before final rules are established. In these cases, some lessees may allow their leases to expire because they cannot determine whether or not their leases will qualify for a royalty suspension volume. We believe this situation contradicts the purpose of the DWRRA and does not serve the public interest.

Any further delay in issuing even interim rules may place some leases at a competitive disadvantage. Fields in deep water may consist of both new leases and leases issued as the result of a lease sale held prior to November 28, 1995. New leases automatically qualify for a royalty suspension volume. Our regulations (30 CFR 260.110(d)(6)) provide that in multiple lease fields, those new leases that first produce the royalty suspension volume are the ones that gain the royalty relief.

Therefore, operators of new leases may proceed with development activities as soon as possible with the certainty that they will receive a royalty suspension volume. Lessees of leases issued as the result of a lease sale held prior to November 28, 1995, must wait until rules are issued before they can determine if they qualify for relief. By going through the usual rulemaking process, lessees of new leases could gain an advantage over these lessees. We believe this to be unfair and that the public interest requires that, to the extent possible, we fully inform lessees and create a ''level playing field'' by issuing this interim rule.

Upon receipt of an application for royalty relief under section 302 of the DWRRA (43 U.S.C. 1337(a)(3)(C)), the Secretary must determine whether new production from the lease or unit is economic in the absence of royalty relief. If the new production is determined to be uneconomic, royalty payments may be suspended on the new production until the suspension volume specified in the DWRRA, or such greater volume as the Secretary determines is necessary to make the new production economically viable, is produced. If the Secretary does not make the determination within 180 days of receiving an application and finding that it is complete, the DWRRA mandates royalty suspension automatically, unless the evaluation period is extended by 30 days, or for longer than 30 days with the applicant's concurrence.

Delaying a rulemaking on this issue also raises a significant question of statutory interpretation as to when lessees may begin submitting applications for royalty relief. One possible interpretation is that they could submit applications for a royalty suspension volume under the DWRRA as soon as the Congressional deadline for the issuance of implementing regulations passed.

Under this interpretation, unless sound application requirements and suspension terms are established by rulemaking before lessees can begin submitting applications, some leases or units could receive automatic royalty suspensions that would otherwise not be granted. In such cases, the royalty relief would unnecessarily penalize the taxpayer and the Federal Treasury. These potential losses could amount to hundreds of millions of dollars. The issuance of an interim rule and associated guidelines will avoid potential problems regarding interpretation of the DWRRA's application provisions.

Thus, prudent public policy and the national interest dictate that we issue this interim rule, thereby avoiding the risk that, however unlikely, the aforementioned interpretation of the statute might prevail.

Issuance of this interim rule will not preclude opportunities for the public to comment on the issues addressed herein. We have considered the comments submitted in response to the ANPR and in the public meeting, and we invite comments on this interim rule. We will also hold another public meeting if there is significant public interest to do so. As with the interim rule on royalty relief for new deep-water leases, a final rulemaking would include the provisions covered by this interim rule. Based on comments received and experience with initial applications, we may make changes to the matters this interim rule addresses when we issue a final rule that implements all provisions of the DWRRA.

The following sections discuss the two types of royalty relief addressed by this interim rule: first, conversion of existing producing leases to NRS leases under the OCSLA's general royalty rate reduction authority; and second, granting of royalty suspension volumes for certain deep-water leases under the new OCSLA provisions added by the DWRRA.

IV. Net Revenue Share Leases

Over the years, we have received 19 applications for royalty rate reductions under the OCSLA statutory provision as implemented by regulations at 30 CFR 203.50. Of these, we approved 10 applications, we denied 7 applications, and we still have 2 applications under review. While this program has produced worthwhile results, our experience with it has led us to believe that its terms and conditions need clarification and restructuring. We also found that applicants needed more information on how to apply for relief, including the data that must be submitted for a complete application.

Accordingly on December 14, 1995, we issued interim ''Guidelines for the Application, Review, Approval, and Administration of the Royalty Relief Program.'' The guidelines were developed to provide industry with clear instructions about how to apply for royalty relief. The guidelines streamline and simplify our royalty relief application process.

This portion of the rulemaking supplements the guidelines with additional direction on the data and information required in applications and revises 30 CFR 203.50 to be consistent with this new approach.

Criteria and Basis for Relief

All active leases or units that are producing or that produced previously are eligible for royalty relief under this section.

Royalty relief will be granted to enable lessees of leases with inadequate revenues to continue production or to encourage lessees to make additional capital investment to expand production. As a condition of approval, an applicant must agree to convert its lease to an NRS lease. The NRS rates will be calculated to allow lessees a return on operating expenses or new capital, as appropriate, while ensuring protection of Federal revenue interests.

Applications

Lessees of eligible leases may apply for royalty relief to the appropriate MMS Regional Director. Applications should be prepared in accordance with the December 1995 guidelines, subsequent updates, and these regulations. The data and information required for a complete application depends on whether the applicant proposes a continuation or expansion of current production.

Applications from lessees of marginal leases with inadequate revenues to sustain production must include certain administrative information, justification for the relief sought, and an NRS economic viability supplemental report (§ 203.53(b) and § 203.55).

Applications from lessees of leases proposing an expansion of production that would be uneconomic without royalty relief must contain certain administrative information, justification for the relief sought, and four supplemental reports:

(1) NRS Economic Viability Report;

(2) Geological and Geophysical Report;

(3) Production Report; and

(4) Engineering Report.

The regulations specify the details of the required information at § 203.55. The format for submitting the required information is presented in the our guidelines.

Review and Evaluation Criteria

To qualify for relief, we must determine, based on the application information, that relief would increase ultimate recovery of reserves extending the productive life of the lease by at least 1 year. Projects that merely accelerate the rate of production do not qualify. This approach is consistent with the OCSLA mandate that royalty relief should ''promote increased production on the lease area.''

For leases with inadequate revenues to sustain production to qualify for relief, we must determine that:

(1) Federal royalty payments over the most recent 12-month period were at least 75 percent of net revenues; and

(2) Federal royalty payments are projected to take an increasing share of net revenues (§ 203.52(c)).

We believe that, under these conditions, production on most leases is likely to be terminated unless relief is available. Thus, to the extent that the relief provided keeps a lease in production, one can say that the relief promoted increased production.

For NRS applications proposing an investment to expand production, we will determine if the proposed project is economic in the absence of royalty relief. If development of the project would be economic, then we will deny the application. If development of the project would not be economic without royalty relief, then the royalty will be converted to a NRS rate sufficient to make the project economically viable, as described in the NRS Guidelines available in the appropriate Regional Office. In those instances where no amount of royalty relief would make the project economic, we will deny the application. We will not count sunk costs in making these determinations.

V. Pre-Enactment Deep-Water Leases

Definitions

As used in the interim rule:

Field means an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geological structural feature and/or stratigraphic trapping condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both.

Pre-enactment deep-water lease (PDWL) means an OCS lease issued as a result of a lease sale held before November 28, 1995. The lease must be in a water depth of at least 200 meters and in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude.

Project to significantly expand production (PSEP) means a project proposed in an approved Supplemental DOCD that will result in an increase in ultimate recovery of resources from the field and that involves a substantial capital investment (e.g., the addition of a fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well projects, etc.). The project must be on a PDWL.

Sunk costs means costs (as specified in § 203.55) of exploration, development, and production incurred after the date of first discovery on the field and prior to the date of application for royalty relief. Sunk costs also include the costs of the discovery well qualified as producible under 30 CFR 250.11.

These terms are defined in 30 CFR § 203.50.

Criteria for Consideration of Relief

We will consider an application for the suspension of royalty payments on a volume of new production from a lease if the lease meets three basic conditions:

- The lease must have been issued as a result of a lease sale held before November 28, 1995, the date of enactment of the DWRRA.
- The lease must be located in water depths of 200 meters or greater.
- The lease must encompass only whole blocks lying west of 87 degrees, 30 minutes West longitude in the Gulf of Mexico.

Units may apply if they include at least one lease that meets these conditions, but any royalty suspension will apply only to those leases in the unit that meet these conditions.

Basis for Granting Relief

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'' is not defined in the DWRRA. A fundamental issue in implementing the DWRRA is: should royalty relief for leases or units be based on some geologic or economic unit, such as a field?

We faced the same issue when we published the interim rule for new leases on March 25, 1996 (61 FR 12022) which amended § 260.110 to implement the provisions of section 304 of the DWRRA. In that instance, new (i.e., ''eligible'') leases receive suspension volumes automatically, without demonstrating a need for the suspension to assure economic viability. We have structured this rule to apply the PDWL royalty suspension provisions consistently with the royalty suspension provisions for new leases. Accordingly, two principles established in that interim rule will apply to this rule too.

First, as set forth for new eligible leases in § 260.110(d), we will allow only one royalty suspension volume per new field (*i.e.*, a field not producing prior to November 28, 1995). We believe Congress added ''or unit'' to section 302 of the DWRRA to allow us to evaluate multi-lease fields. But, in recognition of the objections raised in response to the ANPR regarding the suggestion that we might compel unitization, we will require leases in multi-lease fields that are not unitized to submit a joint application, as discussed below.

We set forth the underlying justification for a field approach in the preamble to the interim rule establishing the royalty suspension regulations for new deep-water leases under section 304 of the DWRRA. Briefly, the minimum royalty suspension volumes which Congress set forth in the DWRRA were developed from technical analysis conducted to estimate the royalty suspension volumes needed for capital cost recovery in developing unproduced oil and gas fields at various water depths in the Gulf of Mexico. This helps explain the fact that the chief Congressional sponsor, Senator Johnston, expressly linked the royalty suspension volumes in the DWRRA to the cost of developing a field.

Senator Johnston explained that the legislation was intended only to provide incentives for drilling leases that would not otherwise be drilled and to bring new fields into production:

> It is only with respect to *those leases that would not otherwise be drilled, either existing or future leases, that this amendment would provide that incentive* * * * The Secretary of the Interior wanted the incentive to be sufficient but not too much. That took a lot of negotiating * * * [The legislation] should bring on at least two new fields with approximately 150 million barrels of oil equivalent from existing leases and *it significantly improves the economics of 10 to 12 possible and probable fields.* 141 Cong. Rec. S. 6731 (daily ed., May 16, 1995) [emphasis added].

This statement strongly indicates that the DWRRA legislation was not intended to provide each lease in deep water the full royalty suspension volume. Granting royalty suspensions on a lease basis could result in much more relief than necessary to bring new fields into production.

As a hypothetical example, assume a field in 600 meters of water (the minimum suspension volume associated with 600 meters of water is 52.5 MMBOE) consists of two leases. Assume that our evaluation of the application under the DWRRA determines that development of the field is uneconomic without a suspension of royalty and that a royalty suspension of 35 MMBOE is needed to make development of the field economically viable. Granting the royalty suspension volume called for in the DWRRA to each lease would result in a total royalty suspension volume of 105 MMBOE, three times the amount necessary to make development of the field economically viable.

Thus, to be faithful to the intent of the DWRRA legislation, the royalty suspension volumes should be applied on a field basis, rather than giving each individual lease a full royalty suspension volume.

Second, if a PDWL is part of a field where any current lease produced prior to November 28, 1995, it cannot receive a royalty suspension volume from that field (except that a royalty suspension may be granted for a lease that undertakes a significant expansion of production on a field that produced before November 28, 1995). Since those lessees who undertook the initial production from the field (and can be said to have taken the most risk) would not be 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 is not necessary to encourage production.

We will assign PDWL's to a field the same as described in the interim rule for new deep-water leases. That is, we will assign a lease to a field when a well on the lease qualifies as capable of producing in paying quantities under the regulations at 30 CFR 250.11. If a well does not qualify under the rule, we will assign the lease to a field when hydrocarbons are first produced from the lease or when the lease is allocated production under an approved unit agreement.

The definition of field is set forth in 30 CFR 203.50. The definition is based on geology. We issue the *OCS Operations Field Names Master List,* which lists all the tracts in each field on the Gulf of Mexico OCS each quarter, with monthly updates.

We recognize that lessees may occasionally disagree with our determination that a lease is part of a particular field. Lessees may appeal these designations to the Director in the same manner as bid rejections are appealed. To appeal a decision that a lease is part of a particular field, a lessee must file a written request to the Director within 15 days of when we designate the lease as part of a field. The Director's response to this request, either affirming or reversing the earlier decision, cannot be appealed further within the Department of the Interior.

The deepest water depth on a lease in a field at the time an approved application for a royalty suspension was submitted establishes the water depth for that field. The water depth of a lease is governed by the ''Royalty Suspension Areas'' maps which we publish prior to lease sales in areas where the deep-water royalty relief program applies. These maps are based on bathymetric data from the National Oceanic and Atmospheric Administration. For purposes of drawing the map, if the water depth contour 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 the field.

Applications

Lessees may submit applications for royalty relief under the provisions of this interim rule to the MMS Regional Director, Gulf of Mexico Region. Lessees may submit applications for:

(1) A PDWL or unit in a field that did not produce (other than test production) prior to November 28, 1995; or

(2) A PDWL or unit proposing development in a supplemental DOCD approved after November 28, 1995, that will expand production significantly beyond the level anticipated in a prior DOCD.

Because we have not required DOCD's to show anticipated production, we have chosen to define significant expansion of production as any project that will result in an increase in ultimate recovery of resources from the field and that involves a substantial capital investment (e.g., installation of a fixed-leg platform, subsea template and manifold, tension-leg platform, or multiple well projects).

The DWRRA directs applicants to provide information required for a ''complete application'' and directs the Secretary to define clearly the information required. This interim rule requires the submission of several reports as part of a complete application. The information required in the reports includes field geology and geophysics, project design, field development and production plan (including planned time that production will begin and rates of production), costs (projected and past, if any), and a discounted cash flow (DCF) analysis of the field development and production.

The Gulf of Mexico Regional Office will make guidelines available to all lessees. These guidelines contain detailed instructions on the specific information and data elements required for a complete application.

As specified in the interim rule at § 203.55(c), the applicant or the applicant's authorized representative must certify that all information submitted in the application is accurate and complete. The application must be accompanied by a report prepared by an independent certified public accountant (CPA) expressing an unqualified opinion on the accuracy of the historical financial information presented in the application. The applicant must make the independent CPA available to us to respond to questions which may arise regarding the evaluation of the historical information. This requirement does not prevent further review of the applicant's records which support the historical financial information included in the application.

In developing the information requirements for a complete application, we observe that much of the geologic and economic information to be provided by an applicant who holds a non-producing PDWL is, by its very nature, imprecise (i.e., estimated or projected). Thus, it is important to set information requirements that enable us to make the DWRRA determinations with reasonable certainty.

To reduce the uncertainty of the information, the application should be submitted as late in the development process as possible, though before production commences. By waiting until later in the development process, activities such as drilling of development wells and procurement of facilities will provide more reliable information about costs and potential future income.

We note that lessees would prefer to have a decision made about relief early in the life of the lease to help in project planning and in arranging financing. Lessees with leases on a field that could be economic with royalty relief want to know whether and how much relief they will receive before making substantial post-discovery investments on their leases. Thus, there is a trade-off between our need for reasonably complete information and the lessee's desire for an early decision.

Our decisions on this issue incorporate ideas developed during ongoing discussions of possible new types of regulatory approvals relating to the development of deep-water oil and gas leases. A reasonably clear point in the OCS lease development process exists when detailed engineering and design activities necessary for the development of discovered resources have been completed, but capital investment for procurement and construction has not begun. The lessee has advanced the engineering, geology, and geophysics to a degree that more certainty exists in comparison to the earlier, exploration stage. Yet, the lessee has not made major financial commitments such as procuring facilities or drilling development wells.

Under the requirements for a complete application, the lessee must provide its design of production facilities needed for field development. The design of development and production facilities reflects the applicant's belief that the field merits development and qualifies for royalty relief. This approach avoids focusing on discoveries that have not yet been delineated and making major investments in the absence of knowledge about whether and to what extent the field qualifies for royalty relief and, if so, how large a royalty suspension volume we will grant.

A complete application must include an approved DOCD for a PDWL or unit or a supplemental DOCD for a PSEP. In joint applications, at least one lessee of a lease participating in the application must have an approved DOCD or an approved supplemental DOCD. The requirement for an approved DOCD for a complete application helps avoid submission of premature applications, since a DOCD covers the major system elements such as the platform and the development wells. A DOCD is not normally submitted to us until development design has progressed to a fairly final stage.

We considered requiring mandatory unitization of leases on a field if necessary to provide for the most efficient development of the field. However, in recognition of the responses to the ANPR in which virtually all lessees who provided comments opposed mandatory unitization, and since we continue to have the authority to compel the unitization of operations on OCS leases on a case-by-case basis, we have elected not to require the unitization of field operations as a necessary feature of a complete application for the suspension of royalty under the DWRRA.

Rather, we are requiring joint application procedures. In applying for royalty relief, all lessees on a field must submit a combined, joint application (§ 203.53(b)(3)(i)). If lessees do not want to share proprietary data with other lessees on the field, the proprietary geologic and geophysical data that is part of the joint application can be submitted separately and we will protect its confidentiality (§ 203.53(b)(3)(ii)). We will not deem the application complete until we receive all the required information for each lease on the field. If the application is subsequently denied, MMS will not disclose a lessee's proprietary data to other lessees in our explanation of our determinations.

The approach we have chosen to pursue for this interim rule represents a reasonable middle ground that protects the public interest while still allowing lessees flexibility of operation. That is, while a joint application that describes joint development of the field is required, lessees may develop their individual leases independently if they so choose.

Some lessees may be unwilling to provide the information necessary for a complete joint application even if it means foregoing an opportunity to share in the royalty suspension volume assigned to a field. In such cases, we will grant a good cause exception to the joint application requirement and will accept and evaluate an application from the remaining lessee(s) (§ 203.53(b)(3)(iii)). The application must include evidence of efforts to gain the cooperation of the non-participating lessee(s). While the noncooperating lessee(s) forfeits the right to receive a royalty suspension for the field that is the subject of the application under these DWRRA provisions, it may apply for royalty relief under other provisions.

Lessee(s) on a field may apply only once for a mandated royalty suspension volume for that field, except under the circumstances described below or for a PSEP (§ 203.53(b)(3)(iv)). The DWRRA specifically allows lessees to request a redetermination under certain limited circumstances, as discussed below. However, if unlimited applications were permitted, there would be no need for the DWRRA's redetermination provisions. Therefore, we believe it is consistent with Congressional intent to allow only one application per field, except under the redetermination criteria or when we withdraw a prior approval of a royalty suspension volume, as discussed below.

Within 20 working days of the receipt of an application, we will determine whether it is complete (§ 203.53(c)(1)(i)). If the application is complete, we will notify the applicant and start to evaluate it. If the application is incomplete, we will provide the applicant an explanation of the additional data we need to make it complete.

The DWRRA provides that if we do not make our required determinations within 180 days after we receive a complete application (or 120 days in the case of a redetermination), we may extend the time period for making our determination or redetermination for 30 days, or for longer than 30 days if agreed to by the applicant (§ 203.53(c)(1)(ii)).

If we do not complete our required determinations in the prescribed time period, the field is granted the minimum royalty suspension volume automatically. In the case of a PSEP, the DWRRA specifies that no royalty is due on such production for a period of one year following the start of such production.

The interim rule specifies that the 180-day time period for our determination, or 120-day time period for redeterminations, begins when we have determined that the application is complete and so notify the applicant.

We view the evaluation process as one where we may interact with the applicant. If, during this process, we find that data or information in the application is unclear, inconclusive, or otherwise cannot be relied upon, we will notify the applicant to provide such new data or information as is needed to make the application complete and accurate. We will request that the 180- or 120-day time period be tolled from the time the applicant receives our notice until the needed information is provided. When the applicant supplies the needed information, we will restart the time period with the same number of days remaining for us to make our determinations as when the time was tolled. The alternative to tolling the clock is for us to reject the application because the data and information does not adequately support the determination we must make under the DWRRA.

Review and Evaluation Procedures

In evaluating applications for deep-water royalty relief, we will make the following determinations:

- Would the new production be economic without a royalty suspension; and
- Is there any royalty suspension volume that we could grant that would make the new production economic?

If the answer to the first determination is that production would not be economic without relief and the answer to the second is that there may be a royalty suspension volume that would make the new production economic, we will proceed to a third determination: what amount of relief should we grant, i.e., the minimum royalty suspension volume mandated in the DWRRA or a volume in excess of that minimum?

The OCSLA authorizes these determinations in section 8(a)(3)(C)(ii). First, the provision reads, ''the Secretary shall determine * * * whether new production from such lease or unit would be economic in the absence of the relief * * *'' Second, that same section mandates that the Secretary ''determine the volume of production from the lease or unit on which no royalties would be due in order to make such production economically viable * * * .'' If there is no amount of royalty relief which would make the new production economic, then there is no way the Secretary can calculate the ''volume of production from the lease or unit on which no royalties would be due in order to make such production economically viable * * * .'' Thus, our determination of whether there exists a royalty suspension volume that would make new production economic is necessary for the Secretary to proceed to a determination of a volume of royalty suspension that would make production economically viable.

If new production from a field or project is economic in the absence of royalty relief, the relief provisions of the DWRRA do not authorize relief and we will reject the application. If no amount of royalty relief would make a field (or project) economic, we will disapprove the application. In such a case, the royalty relief would not induce the lessee to develop the field or marginal project.

The DWRRA requires us to determine whether new production would be ''economic'' taking into consideration the risks of deep-water development and all costs associated with exploration, development, and production. However, the term ''economic'' is not defined in the DWRRA. For this interim rule, we have defined ''economic'' as a project or group of related projects, such as field-wide development, having a positive net present value as calculated with MMS-stipulated DCF techniques.

The DWRRA requires us to consider all costs of exploration, development, and production in determining whether a field is economic in the absence of royalty relief. In making this determination, we will include only those sunk costs incurred after the date of field discovery because of the difficulties in attributing to a particular field those sunk costs incurred before a discovery.

Similarly, we will not include sunk costs when we determine whether a field can be made economic with royalty relief or when we determine the amount of royalty suspension volume needed to make the new production economic. First, only prospective costs are relevant to determining the royalty suspension volume needed to make the new production economic. Second, the DWRRA does not state that ''all costs'' must be considered in determining the appropriate suspension volume.

This treatment of sunk costs applies only to fields that did not produce, other than test production, prior to the date the application for royalty suspension is submitted. We will not count any sunk costs where production commenced prior to the date the application is submitted or when the application is proposing a significant expansion of production. According to economic theory, such costs generally are not relevant to decisions about whether to continue producing from a developed field. Since the intent of the DWRRA is to bring new fields into production-not to ensure a rate of return on developed fields-we will not count sunk costs in such cases.

The guidelines provide more detailed information on costs, prices, and discount rates. In general, the applicant provides the cost data we use to make our determinations. Based on our experience in administering NRS royalty relief, we will not include some types of costs in the analysis, as specified in § 203.55(b). We will verify the costs reported and, where sunk costs are important, this verification may include an audit of those costs. The costs and the underlying geology and design data are given in ranges or with probability distributions, reflecting the uncertainties and risks of the field development.

We will provide applicants with the assumptions for oil and gas prices to use in the DCF analyses. We will develop future price assumptions after considering long-term projections of oil and gas prices by major forecasters, such as (but not limited to) the Energy Information Administration, Data Resources Incorporated, and Wharton Econometrics. We will update these price forecasts periodically. These assumptions provide reasonable forecasts that all applicants can employ. Applicants may adjust prices for the expected quality of the resource, documenting these adjustments as discussed in our guidelines.

We will also specify a range of discount rates from which applicants will choose a particular rate. The reason for allowing a choice of discount rates is that projects differ in their risk characteristics, and further, operators might have different risk preferences reflected in their target rates of return. Our guidelines will set the range of discount rates for use in the DCF analyses. We may change the range periodically.

In determining the volume suspension needed to make the field economically viable, we will employ a similar DCF model and the same price and discount assumptions used to show whether royalty relief can make the field economic. We will also input the geological assessments, engineering designs, production scenarios and cost components included in the application, subject to our review and verification of their accuracy and efficiency. In cases where we find that assumptions other than those provided by the applicant are more appropriate, we reserve the right to make all necessary changes in the set of inputs.

In general, we have structured our determinations following the principle that the DWRRA aimed to give substantial, but not excessive, incentive to develop marginal fields. In this manner, we seek to avoid the errors of rejecting deserving applications or giving large amounts of volume suspension when they are not needed.

Note that being granted a royalty suspension volume on production from a PDWL under the regulations established by this rulemaking does not preclude a lessee 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.

Also, as noted above a lessee may apply only once for a royalty suspension volume for a given field under the DWRRA provisions, except as provided below.

Redeterminations

The DWRRA provides that an applicant may request a redetermination of the Secretary's findings prior to the start of new production if a significant change occurs in the factors upon which we based the original determination. We believe that the Congress established this requirement, in part, to place reasonable limits on the number and frequency of redetermination requests so the Secretary would not need significant new staff resources to administer the program.

Accordingly, we will accept an application for a redetermination only when:

(1) Changes in resource information (e.g., gross resources, quality, flow rates) are of sufficient magnitude that, had our evaluation of the original application included the new data, the results of our determinations would have been materially different. The new resource information must result from new exploration activity such as drilling a new well or acquiring new 3–D seismic data that did not exist at the time of the original application. A reinterpretation of existing data does not qualify as a significant change in resource information; or

(2) Average annual prices of oil and gas have fallen by 25 percent since the previous application. These averages are determined by:

(A) using daily closing prices for light sweet crude oil and natural gas on the New York Mercantile Exchange (NYMEX) over 12-month periods; and

(B) weighting the annual average prices by the volumes of oil and gas (in barrels of oil equivalent) identified in the most likely development and production scenario (required under § 203.55 and described in the guidelines) in the previous application for royalty relief. (See § 203.53(d)(1)(ii) for details.)

We are establishing this condition to avoid having economic projects appear uneconomic, and therefore qualify for a royalty suspension volume, due to what may only be a brief temporary downturn in prices. While smaller price changes can affect the economic viability of development, larger, sustained changes in underlying prices must occur before we would change the price scenarios used in evaluating applications. Further, a drop in oil prices should not trigger a potential redetermination for a project proposing to develop a 100 percent gas field or vice versa. Therefore, the weighted average price change is required; or

(3) Prior to starting construction of your project, estimated project development costs amount to more than 120 percent of the eligible development costs included for the most likely development scenario as set forth in the previous application.

Applicants requesting a redetermination must include a new complete application in accordance with the requirements of § 203.53(b) and § 203.55. We will evaluate the request to see if the applicant is eligible for a redetermination. If so, we will proceed to evaluate the application.

As with an original application for a royalty suspension, we have 20 working days to determine whether an application for a redetermination is complete. If the application is complete, we must evaluate the application within 120 days. We can extend this period for 30 days, or longer if agreed to by the applicant(s).

Withdrawal of Approvals and Changes in Material Fact

If we find that an applicant provided false historical information or intentionally inaccurate data that was material to us in granting royalty relief under this section, we will rescind our approval of that relief as of the date of the approval. The applicant must pay royalties and late payment interest determined under 30 U.S.C. 1721 and 30 CFR 218.54 on all volumes of production on which royalty was not paid. The lessee also may be subject to penalties under other provisions of law.

We further reserve the right to withdraw our approval of a royalty suspension if a change in material fact occurs that is significant enough to invalidate the basis on which we originally evaluated and approved the application. Material changes that will result in a withdrawal of an approved royalty suspension volume include:

(1) The lessee changes the type of development system proposed in the approved application. For example, the development proposal changes from a stand-alone platform, as proposed in the approved application, to a much less expensive subsea template and tie-back.

(2) Construction of the production system described in the application does not commence within 2 years of the date of application approval, notwithstanding any suspensions of operations.

(3) Actual development costs incurred prior to the commencement of production, other than test production, amount to less than 80 percent of the estimated development costs included for the most likely development and production scenario presented in the approved application.

We will use the pre-production report (§ 203.53(c)(4)) to determine whether the actual capital costs meet this threshold. As an incentive for efficient investment and to provide greater certainty at the time of the application, a portion of the originally granted royalty relief can be automatically retained. If the applicant informs us of the development cost discrepancy in the pre-production report, the applicant will be entitled to 50 percent of the approved royalty suspension volume with no further action required (see § 203.53(e)(3)(i)). If we discover the development cost discrepancy after production, other than test production, has started, approval of the royalty suspension volume will be retroactively withdrawn (see § 203.53(e)(3)(iii)).

However, if the royalty suspension volume resulted from a redetermination based on a change in capital costs, as discussed above, we will withdraw our approval of the application if actual development costs are less than 90 percent of the estimated development costs included in the most likely development and production scenario in the approved application, and the lessee will not be permitted to retain any of the approved royalty suspension volume (see § 203.53(e)(3)(ii)).

We considered other factors as grounds for withdrawal of our approval of an application, but we concluded that the factors discussed above were sufficient to protect the public interest.

The applicant may initiate a new application for a suspension volume when its previously approved royalty suspension volume is withdrawn for reasons other than the submission of false information or intentionally inaccurate data.

The material changes triggering a potential withdrawal of approval of the royalty suspension volume are at least partially at the discretion of the lessee(s) and the potential for a subsequent withdrawal of our approval for a royalty suspension should be considered by applicants when deciding to make changes of this nature.

Allocation Rules

Fields in deep water may consist of one or more leases, including leases issued as a result of sales held before and after November 28, 1995, and leases in different water depths. Therefore, to make royalty relief consistent with the DWRRA, we need to specify how the royalty suspension volume applies in many different circumstances. Accordingly, the following cases illustrate how the rule applies in determining eligibility for, and the volume of, royalty suspensions. (All cases assume that all eligible leases on a field participate in the joint application for a royalty suspension volume; the term ''eligible leases'' is defined in the interim rule for deep-water royalty relief on leases issued from sales after November 28, 1995 (61 FR 12022, 30 CFR 260.110)).

Case 1. If a field consists of a single PDWL and the application is approved, no royalty payment is required on production from the lease until that production equals the royalty suspension volume granted.

Case 2. If a field consists of more than one PDWL and the application is approved, payment of royalties on production from the PDWL's is suspended until their cumulative production equals the suspension volume granted. The royalty suspension volume for each lease equals each lease's actual production (or production allocated under an approved unit agreement) until cumulative production from the field equals the field's royalty suspension volume.

Case 3. If a PDWL or an eligible lease is added to a field that has been granted a royalty suspension volume under the regulation established by this rulemaking, the field's royalty suspension volume will not change. The additional lease may receive a royalty suspension volume only to the extent of its production before the cumulative production from the field equals the approved royalty suspension volume.

In this case, the added PDWL will not be required to submit the full application required of the original applicants. A full application is not necessary because we have already evaluated the field and set an appropriate royalty suspension volume. We see no need to reevaluate that determination. Accordingly, the operator of the PDWL can apply for relief using an abbreviated application available at the Gulf of Mexico OCS Regional Office.

Case 4. If the PDWL is part of a field that has a royalty suspension volume for eligible leases under § 260.110, the lessee(s) may apply for relief. If the application meets the economic and economic viability tests, all of the leases can share the royalty suspension volume until total cumulative production from the field attains the royalty suspension volume that is the greater of the volume established for the eligible leases under § 260.110 or the volume determined pursuant to the regulation established by this rulemaking.

Case 5. A lease may receive more than one royalty suspension volume. An application may be made for relief for a lease under the regulations established by this rulemaking for each field that includes the lease. Each field will receive a separate royalty suspension volume if it meets the evaluation criteria described below. An application also may be made for relief for a project that would result in a significant expansion of production, even if we have already granted a royalty suspension volume to the field that encompasses that project. For a PSEP, this is how the rule applies:

Case 6. If a PDWL is the only lease on the project and the application based on a significant expansion of production is approved, no royalty payment is due on the incremental production from the project until that production equals the royalty suspension volume granted.

Case 7. If the expansion of production project includes more than one lease and the application is approved, payment of royalties on incremental production from the project is suspended until the lessees' cumulative incremental production from the project equals the suspension volume granted. The royalty suspension volume for each lease equals each lease's actual production from the project until cumulative production equals the project's royalty suspension volume.

In all cases, the addition of a lease to a field that has an established royalty suspension volume will not change the field's royalty suspension volume, even if the added lease is in deeper water.

Other Issues

Appeals—Our determinations and redeterminations under 43 U.S.C. 1337(a)(3)(C) are final agency actions which are judicially reviewable under section 10(a) of the Administrative Procedure Act (5 U.S.C. 702). Requests for judicial review of a determination or redetermination under 43 U.S.C. 1337(a)(3)(C) must be filed within 30 days of our decision.

Gas-to-oil conversion factor—The royalty suspension volumes are measured in millions of barrels of oil equivalent. For the purposes of this rule, 5.62 thousand cubic feet of natural gas equal one barrel of oil equivalent, as measured at 15.025 pounds per square inch (psi) pressure, 60 degrees Fahrenheit, and fully saturated (§ 203.53(g)(5)). This is the conversion factor traditionally used in the Gulf of Mexico and is the same factor specified in § 260.110(d)(11) for calculating royalty suspension volumes for new leases.

Non-royalty bearing production—Under this rule, any lease-use production that otherwise is not subject to royalty does not count toward the royalty suspension volume.

Price escalation clause—In accordance with section 302, in any calendar year during which the arithmetic average of the daily closing prices on the NYMEX for light sweet crude oil exceeds $28.00 per barrel, adjusted for inflation as described below, any royalty relief we grant under the provisions of this rule for DWLP's and PSEP's is suspended and any production of oil is subject to royalties at the lease stipulated royalty rate. However, this production counts as part of the established royalty suspension volume. By January 31 of the year following the calendar year in which the price exceeded $28.00 per barrel, the lessee must pay the royalty due plus interest in accordance with 30 U.S.C 1721 and 30 CFR 218.54, on any volume of oil produced during the previous year on which no royalties were paid.

In any year following a calendar year in which the arithmetic average of the daily closing prices on the NYMEX for light sweet crude oil exceeded $28.00 per barrel, as adjusted for inflation, the lessee must pay royalties on all the oil it produces that year. If, after the end of the year, the arithmetic average of the daily closing prices on the NYMEX for light sweet crude oil for that year was $28.00 per barrel or less, as adjusted for inflation, the lessee is entitled to a refund or credit, with interest, of royalties paid that year on any royalty suspension volume for oil production. Regulations for receiving refunds or credits are at 30 CFR part 230.

This rule similarly applies to natural gas. In any calendar year during which the arithmetic average of the daily closing prices on the NYMEX for natural gas exceeds $3.50 per million British thermal units (Btu's), adjusted for inflation as described below, any royalty relief we grant under the provisions of this rule for DWLP's and PSEP's is suspended and any production of gas is subject to royalties at the lease stipulated royalty rate. However, this production counts as part of the established royalty suspension volume. By January 31 of the year following the calendar year in which the price exceeded $3.50 per million Btu's, the lessee must pay the royalty due plus interest in accordance with 30 U.S.C 1721 and 30 CFR 218.54, on any volume of gas produced during the previous year on which no royalties were paid.

In any year following a calendar year in which the arithmetic average of the daily closing prices on the NYMEX for natural gas exceeded $3.50 per million Btu's, as adjusted for inflation, the lessee must pay royalties on all the gas it produces that year. If, after the end of the year, the arithmetic average of the daily closing prices on the NYMEX for natural gas for that year was $3.50 per million Btu's or less, as adjusted for inflation, the lessee is entitled to a refund or credit, with interest, of royalties paid that year on any royalty suspension volume for gas production. Regulations for receiving refunds or credits are at 30 CFR part 230.

To adjust for inflation, change the prices referred to above (i.e., $28.00 per barrel for light sweet crude and $3.50 per million Btu's for natural gas) during each calendar year after 1994 by the percentage, if any, by which the implicit price deflator for the gross domestic product changed during the preceding calendar year.

The particulars of this provision of the DWRRA are included at § 203.53(h)(6)–(8) of this rulemaking.

Termination of royalty suspension volumes—A royalty suspension will continue until the end of the month in which the cumulative production from the applicable leases in the field or project reaches the royalty suspension volume for the field or project. We will provide monthly production data to all lessees in the field or project. However, this data may not become available until shortly after production exceeds the royalty suspension volume. In such cases, royalties still will be due on the last day of the second month following the month in which cumulative production from the field or project reaches the royalty suspension volume. Any royalties paid late will be subject to interest pursuant to 30 CFR 218.54.

VI. Recovery of Costs

In accordance with Federal policy and statute, we will charge lessees applying for royalty relief under the provisions of the regulation promulgated by this rulemaking an amount which recovers our cost of processing their applications. The Administrative Procedure Act (31 U.S.C. 9701) and Office of Management and Budget Circular A–25 require that agencies recover their costs when they 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, the collection of such fees is specifically authorized by the Omnibus Appropriations Bill (Pub. L. 104–134, 110 Stat. 1321, April 26, 1996). The statute provides: ''That beginning in fiscal year 1996 and thereafter, fees for 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 estimate that our costs for processing NRS applications will range from $8,500 (continuation of production) to $22,500 (project involving capital expansion). For applications for deep-water royalty relief, we estimate that our costs will range from $27,500 to $50,000 depending on the number of leases involved and the complexity of the proposed development project. For some applications, we may find it necessary to audit the financial data submitted to make an adequate determination on the economics of the proposed development. We estimate that it will cost us up to $40,000 to conduct such an audit.

We will issue a Notice to Lessees (NTL) that will provide more detailed information on the amounts of royalty relief application processing costs and when and how applicants may make payments to us. We will revise the NTL periodically to reflect our cost experience and to provide other information helpful or necessary for the administration of this program.

VII. Administrative Matters

Executive Order (E.O.) 12866

The interim rule is significant due to novel policy issues arising out of legal mandates, and the Office of Management and Budget (OMB) has reviewed this rule. We will make a copy of this determination available on request.

We focused on impacts on royalty revenues of regulatory alternatives in determining the possible economic effects of implementing section 302 of the DWRRA. We assumed that there would not be significant impacts on labor and capital because, given current constraints on the availability of deep-water drilling rigs, companies active in these areas would make similar alternative investments in the absence of the DWRRA over the near term.

We analyzed two alternatives for implementing section 302. The approach in this interim rule (MMS approach) gives a single royalty suspension volume for each qualifying field. The alternative approach gives each individual lease or unit separate royalty suspension volumes, subject to the minimum volumes specified in the DWRRA.

Because the DWRRA instructs us to grant royalty relief only in situations that are uneconomic at the lease-stipulated royalty rate, the revenue effects are the additional royalties that may be collected from fields that would otherwise not be developed until a later time, if at all. We estimated these effects by extrapolating to all known deep-water fields the results of detailed analyses of 30 fields in the relevant water depths. The MMS approach generates up to an estimated $45 million per year in royalty revenue in peak years. The alternative approach frequently results in no royalty payments, and when such payments do occur, they would be less than the royalties received under the MMS approach. Thus, in both cases, the economic effects are less than $100 million annually.

We chose the approach embodied in this interim rule because:

• The DWRRA's primary author stated that he intended the DWRRA to encourage production from new fields without providing too much relief;

• The MMS approach provides a substantial incentive for developing marginal fields in deep water while still ensuring a reasonable return to the Treasury;

• The minimum suspension volumes specified in the DWRRA were derived from an analysis of fields, not individual leases; and

• This rule needs to be consistent with the rules for royalty suspensions on deep-water tracts leased after November 28, 1995, in the same parts of the Gulf of Mexico so that all deep-water OCS lessees receive equitable treatment.

Regulatory Flexibility Act

This rule will not have a significant effect on small entities.

This rule establishes the terms and conditions for granting royalty relief under the provisions section 8(a)(3)(A) of the OCSLA and royalty suspension volumes under the DWRRA for certain deep-water OCS Gulf of Mexico leases that were issued as the result of a lease sale held prior to November 28, 1995.

The estimates of development costs for fields in the deep water of the Gulf of Mexico range from over $10 million to about $2 billion. We, therefore, concluded that, in general, the entities that engage in offshore oil and gas development and production activities are not small due to the technical and financial resources and the experience needed to safely conduct such activities.

Small entities who are likely to work in the deep waters of the OCS are primarily contractors who provide services such as catering or custodial services for manned facilities. This rule will impact these entities only to the degree that the royalty relief provided results in the drilling of additional wells and installation of additional manned facilities.

Administrative Procedure Act

We have determined, in accordance with 5 U.S.C. 553(b)(3)(B) of the Administrative Procedure Act, that a notice of proposed rulemaking is not required and is impracticable in the issuance of this rule. We invite comments on this interim rule so changes can be made in the future, if warranted.

Paperwork Reduction Act

The MMS has submitted the information collection requirements in 30 CFR 203 to the Office of Management and Budget (OMB) with a request for emergency processing. We have stated that the time period for OMB approval should coincide with the effective date of this Interim Rule. The information collection in this rule has been approved on an emergency basis through August 31, 1996, under OMB control number 1010–0071. However, we still will conduct a full review and comment process for this collection of information. The new title, ''30 CFR 203, Relief or Reduction in Royalty Rates,'' is consistent with that of the interim final rule for Part 203.

Send comments regarding the burden or any other aspect of the collection of information contained in this part, including suggestions for reducing the burden, to the Information Collection Clearance Officer, Minerals Management Service, Mail Stop 2300, 381 Elden Street, Herndon, VA 22070–4817 and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attn: Desk Officer for the Department of the Interior (OMB control number 1010–0071), Washington, DC 20503.

The Paperwork Reduction Act of 1995 provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

Respondents to this collection of information are Federal oil and gas lessees. The frequency of response is on an occasion basis. We expect the number of responses (applications) for the remainder of this fiscal year to be relatively small. The number will peak during fiscal year 1997 and decline thereafter. The following chart represents an average of the anticipated number of annual applications over a three year period and the associated reporting burdens. The burden estimates include the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

OCSLA

Type of application	Responses per year	Hours per response	Hours per year
Leases with inadequate revenues to sustain continued production	4	300	1,200
Leases proposing an expansion of production that would be uneconomic absent relief	7	800	5,600
Total annual burden			6,800

DWRRA

Type of Application	Responses per year	Hours per response	Hours per year
DWRRA lease on a field that did not produce prior to 11/28/95	23	1,200	27,600
DWRRA leases proposing a significant expansion of production	7	800	5,600
Redetermination	6	800	4,800
Short Form Applications	7	40	280
Total annual burden			38,280

In addition to the hour burden outlined above, there are two other cost burdens to the respondents. (1) We will charge lessees (respondents) applying for royalty relief an amount which covers the cost of processing their applications. This is discussed above in Section VI. Recovery of Costs. (2) A respondent's application or pre-production report must be accompanied by a report prepared by an independent certified public accountant as described in section 203.55(c) of the rule.

Takings Implication Assessment

The Department of the Interior certifies that this rule does not represent a governmental action capable of interference with constitutionally protected property rights. A Takings Implication Assessment prepared pursuant to E.O. 12630, Government Action and Interference with Constitutionally Protected Property Rights, is not required.

E.O. 12988

The Department has certified to the OMB that this regulation meets the applicable standards provided in section 3(b)(2) of E.O. 12988.

National Environmental Policy Act

We examined the interim rule and have determined that it does not constitute a major Federal action significantly affecting the quality of the human environment pursuant to section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332).

Unfunded Mandate Reform Act of 1995

This rule does not contain any unfunded mandates to State, local, or tribal governments or the private sector.

List of Subjects in 30 CFR Part 203

Continental shelf, Government contracts, Indians-lands, Minerals royalties, Oil and gas exploration, Public lands—mineral resources, Sulfur.

Dated: May 20, 1996.

Bob Armstrong,

Assistant Secretary, Land and Minerals Management.

For the reasons in the preamble, the Minerals Management Service (MMS) is amending 30 CFR part 203 as follows:

PART 203—RELIEF OR REDUCTION IN ROYALTY RATES

1. The authority citation for part 203 continues to read as follows:

Authority: 25 U.S.C. 396 *et seq.*; 25 U.S.C. 396a *et seq.*; 25 U.S.C. 2101 *et seq.*; 30 U.S.C. 181 *et seq.*; 30 U.S.C. 351 *et seq.*; 30 U.S.C. 1001 *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.*

2. Subpart A is added to read as follows:

Subpart A—General Provisions

§ 203.1 Authority for information collection.

(a) The Office of Management and Budget (OMB) approved the information collection requirements in part 203 under 44 U.S.C. 3501 *et seq.* and assigned OMB control number 1010–0071. The MMS uses the information to determine whether granting a royalty relief request will result in the production of resources that would not be produced without such relief. The application for royalty relief must contain sufficient financial, economic, reservoir, geologic and geophysical, production, and engineering data and information to determine whether relief should be granted in accordance with applicable law. the application also must contain sufficient data and information to determine whether the requested relief will result in an ultimate increase in resource recovery and provide for reasonable returns on project investments. The applicant's requirement to respond is related only to the request to obtain royalty relief. The applicant has no obligation to make this request.

(b) An agency may not conduct or sponsor, and you are not required to respond to, a collection of information unless it displays a currently valid OMB control number.

(c) Send comments regarding the burden of this information collection or any other aspect of the collection of information under provisions of this part, including suggestions for reducing the burden, to the Information Collection Clearance Officer; Minerals Management Service, Mail Stop 2300, 381 Elden Street; Herndon, Virginia 20170–4817 and the Office of Management and Budget; Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of the Interior (1010–0071); Washington, DC 20503.

(d) The MMS will protect information considered confidential or proprietary under applicable law and under regulations at § 203.53(b)(ii) and part 250 of this chapter.

3. Subpart B is revised to read as follows:

Subpart B—OCS Oil, Gas, and Sulfur, General

Sec.

Subpart B—OCS Oil, Gas, and Sulfur, General

§ 203.50 Definitions.

Terms used in this part have the following meaning:

Field means an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geological structural feature and/or stratigraphic trapping condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both.

Pre-enactment deep-water lease (PDWL) means an Outer Continental Shelf (OCS) lease issued as a result of a lease sale held before November 28, 1995. The lease must be in a water depth of at least 200 meters and in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude.

Project to significantly expand production (PSEP) means a project proposed in an approved Supplemental Development Operations Coordination Document (DOCD) that will result in an increase in ultimate recovery of resources from the field and that involves a substantial capital investment (e.g., the addition of a fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well projects). The project must be on a PDWL.

Sunk costs means costs (as specified in § 203.55) of exploration, development, and production incurred after the date of first discovery on the field and prior to the date of application for royalty relief. Sunk costs also include the costs of the discovery well qualified as producible under 30 CFR 250.11.

§ 203.51 What is MMS's authority to grant royalty relief?

Under the OCS Lands Act, 43 U.S.C. 1337, as amended by the OCS Deep Water Royalty Relief Act, Public Law 104–58, MMS may grant three types of royalty relief listed in this section.

(a) Under 43 U.S.C. 1337(a)(3)(A), MMS may reduce, suspend, or eliminate the royalty specified for any producing OCS lease to promote increased production. If your OCS lease has inadequate revenues to sustain production or if you are proposing a project to expand production that would be uneconomic without royalty relief, MMS may grant royalty relief as specified in these regulations at § 203.52 (Net Revenue Share Royalty Relief).

(b) Under 43 U.S.C. 1337(a)(3)(B), MMS may grant royalty reductions or suspensions to promote development, increase production, or encourage production of marginal resources on producing or non-producing leases in the Gulf of Mexico, west of 87 degrees, 30 minutes West longitude. Section 203.54 is reserved for the regulations to implement this provision.

(c) Under 43 U.S.C. 1337(a)(3)(C), if your PDWL is on a field that did not produce before November 28, 1995, or if you have a PDWL where you propose a PSEP, MMS may suspend royalties for volumes of new production which would be uneconomic without royalty relief as specified in these regulations in § 203.53 (Royalty relief for certain deep-water leases in the Gulf of Mexico).

§ 203.52 Net revenue share royalty relief.

(a) *How do I apply for net revenue share (NRS) royalty relief?*

This section explains how to obtain royalty relief under 43 U.S.C. 1337(a)(3)(A) if your lease has inadequate revenues to sustain production or if you are proposing a project to expand production that would be uneconomic without royalty relief. To apply for relief, submit a complete application to the appropriate MMS Regional Director in accordance with this section and the applicable guidelines in § 203.52(b) and § 203.55. An application fee in accordance with § 203.56 must accompany the application.

(b) *What do I need to include in my application?*

(1) A complete application for royalty relief must include an original and two copies of:

(i) Administrative Information and Relief Justification, and

(ii) Net Revenue Share Economic Viability Report.

(2) If you are proposing a project to expand production that would be uneconomic without royalty relief, your application must also include two copies (one set of digital information) of:

(i) Geologic and Geophysical Report;

(ii) Production Report; and

(iii) Engineering Report.

(3) Section 203.55 describes the reports required for the complete application. The appropriate regional office will provide specific guidance on the format for the required reports.

(c) *What are the NRS royalty relief approval criteria?*

(1) MMS may grant your request for royalty relief only if it concludes that royalty relief will increase the ultimate recovery of hydrocarbons by extending lease production for at least one year. However, if you are proposing a project to expand production, MMS will approve your request for royalty relief only if the proposed project would be uneconomic without royalty relief.

(2) If you have a lease with inadequate revenues to sustain production, MMS may grant your request for royalty relief only if it concludes that:

(i) royalties paid to MMS over the most recent 12-month period exceed 75 percent of net revenues; and

(ii) royalties are projected to take an increasing share of net revenues over the next 12 months.

(d) *What royalty relief will MMS grant?*

(1) Except as provided in paragraph (d)(2)of this section, if you meet the royalty relief criteria of this section, MMS may offer to modify the royalty terms of your lease to a NRS. The percentage of the net revenue due to MMS will be established in the MMS NRS guidelines available in the appropriate Regional Office.

(2) If you are proposing a project to expand production but no amount of royalty relief would make the project economic, MMS will deny the request for royalty relief.

§ 203.53 Royalty relief for certain deep-water leases in the Gulf of Mexico.

(a) *Who may apply for deep-water royalty relief?*

This section explains how to obtain royalty relief under 43 U.S.C. 1337(a)(3)(C). You may apply for royalty relief if you are a lessee of a PDWL or a unit that contains one or more PDWL's, subject to the limitation in paragraph (b)(3) of this section. You may apply for relief if:

(1) your lease or unit is part of a field from which no royalties were due on production, other than test production, prior to November 28, 1995; or

(2) you are proposing a PSEP.

(b) *How do I apply for deep-water royalty relief?*

(1) You must submit a complete application to the MMS Regional Director of the Gulf of Mexico OCS Region. An application fee in accordance with § 203.56 must accompany the application.

(2) A complete application includes an original and two copies (one set of digital information) of:

(i) Administrative Information and Relief Justification;

(ii) Deep-Water Royalty Relief Economic Viability Report;

(iii) Deep-Water Royalty Relief Cost Report;

(iv) Geologic and Geophysical Report;

(v) Production Report; and

(vi) Engineering Report.

Section 203.55 describes what these reports must include. The Gulf of Mexico Regional Office will provide specific guidance on the format for the required reports.

(3) For a royalty suspension on production from fields from which no royalties were due on production, other than test production, before November 28, 1995:

(i) Except as provided in paragraph (b)(3)(iii) of this section, MMS will accept only one joint application for all leases that are part of the field on the date of application. The Regional Director maintains a list of all leases in each discovered field.

(ii) If a lessee does not want to share proprietary data with other lessees on the field, that lessee may submit separately to MMS the proprietary geological or geophysical data that is a necessary part of the joint application. The application is not complete until MMS receives all the required information for each lease on the field. In explaining its assumptions and reasons for its determinations under this section, MMS will not disclose proprietary data.

(iii) MMS will waive the joint application requirement if the applicant(s) shows good cause for the waiver. The applicant also must demonstrate that it made a good faith effort to obtain the participation of all lessees in the field. A lease that is part of the field on the date of application but that is not included in the application because its lessee(s) fails or refuses to participate is not eligible for the royalty relief for the field that is the subject of the application. However, that lessee still may apply for other royalty relief under this section.

(iv) With the exceptions listed below, the lessees on a field may submit only one complete application for royalty relief during the life of the field. However, lessees may submit another application if:

(A) They are eligible to apply for a redetermination under § 203.53(d)(1);

(B) MMS has withdrawn approval of a previously granted royalty suspension under § 203.53(e);

(C) they apply for royalty relief for a PSEP; or

(D) they withdraw the application before MMS deems it complete.

(c) *How will MMS evaluate an application?*

(1)(i) MMS will determine within 20 working days if your application for royalty relief is complete. If your application is incomplete, MMS will provide you with an explanation of what it needs to become complete. If you withdraw your application after MMS has deemed it complete, you may only reapply under the redetermination provision of § 203.53(d).

(ii) When MMS determines that your application is complete, MMS will evaluate the application within 180 days. MMS may extend the 180-day evaluation period for an additional 30 days, if necessary, to complete the evaluation. If you agree, MMS also may extend the 180-day period for more than 30 days.

(iii) If MMS must audit sunk costs to evaluate your application, MMS may request that the 180-day evaluation period be tolled from the time you receive notice from MMS until you provide the records necessary to conduct the audit.

(iv) If MMS determines during the evaluation period that it cannot evaluate your application because:

(A) vital information is missing;

(B) the data and information provided in support of the application are inconclusive; or

(C) of any other valid reason;

MMS may request that the 180-day evaluation period be tolled from the time you receive notice from MMS until you provide needed data, explanations, or revisions.

(2)(i) If your application is for a suspension of royalties on production from a field from which no royalties were due on production, other than test production, before November 28, 1995, MMS will determine if development of the field is economic without royalty relief. MMS will include your sunk costs in making this determination. If MMS determines that development of the field would be economic without relief, MMS will deny your request for a royalty suspension.

(ii) For fields that did produce, other than test production, before the date of application, MMS will not include your sunk costs when it determines if development of the field is economic without royalty relief. If MMS determines that development of the field would be economic without relief, MMS will deny your request for a royalty suspension.

(iii) If MMS determines for a field subject to either paragraph (c)(2) (i) or (ii) of this section that development of the field would not be economic without a royalty suspension, and that a royalty suspension could make the project economic, MMS will determine the size of the royalty suspension volume necessary to make the field economically viable. MMS will determine your royalty suspension volume subject to the minimum royalty suspension volumes specified in paragraph (h)(1)(i) of this section. MMS will not include sunk costs when it makes this determination.

(iv) If no amount of royalty suspension would make the field economic, MMS will deny your request for royalty relief.

(3)(i) If your application for royalty relief is for a PSEP, MMS will determine if the proposed project is economic without royalty relief. If it is economic, MMS will deny your request for royalty relief.

(ii) If MMS determines that development of the project would not be economic without royalty relief, MMS will determine the royalty suspension volume necessary to make the project economically viable.

(iii) If no amount of royalty suspension volume would make the project economic, MMS will deny your request for royalty relief.

(iv) MMS will not include sunk costs in evaluating applications for royalty relief for a PSEP.

(4) If MMS approves your application for royalty relief, you must submit a pre-production report 60 days before the planned start of production which is subject to the royalty suspension volume, as specified at § 203.55.

(d) *When will MMS reconsider its determination?*

(1) You may request a redetermination of either a denial of an application or the size of the royalty suspension volume granted in an approved application. However, you may request a redetermination only if you have not started producing hydrocarbons subject to the royalty suspension and one of the following situations occurs:

(i) You have significant new geologic or geophysical data that did not exist at the time of the previous application and that causes you to change your estimates of gross resource size, quality, or projected flow rates. Examples of new data include results from drilling new wells or obtaining new three-dimensional seismic data and information. Reinterpretation of existing data is not significant new data. The change in resource information must be sufficient to materially affect the results of the previous determination.

(ii) Prices for oil or gas have decreased at least 25 percent, determined as follows:

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

(B) Calculate the weighted average prices for oil and gas calculated under (d)(1)(ii)(A) of this section using the volumes of oil and gas identified in the most likely scenario (required under § 203.55) described in your previous complete application for royalty relief.

(C) Perform the same calculations as required in paragraphs (d)(1)(ii)(A) and (B) of this section, but use the arithmetic average of daily closing prices for light sweet crude oil and for natural gas on the NYMEX for the 12-month period preceding the date of your previous complete application.

(D) If the weighted average price calculated under paragraph (d)(1)(ii)(B) of this section is at least 25 percent less than the weighted average price calculated under paragraph (d)(1)(ii)(C) of this section, then you satisfy the requirements of this paragraph; or

(iii) Prior to starting construction of your development/production system, you have revised your estimated development costs, and they are at least 120 percent of the eligible development costs associated with the most likely scenario described in your previous complete application.

(2)(i) Your request for a redetermination must include a new complete application, as discussed in paragraph (b) of this section and § 203.55. MMS will evaluate your application for a redetermination under paragraph (c) of this section.

(ii) MMS will determine within 20 working days if your application for a redetermination is complete. If your application is incomplete, MMS will provide you with an explanation of what it needs to become complete. If MMS later determines that your application does not meet any of the criteria under (d)(1)(i),(ii), or (iii) of this section, it will consider your application incomplete.

(iii) When MMS determines that your application is complete, MMS will evaluate the application within 120 days. MMS may extend the 120-day evaluation period for an additional 30 days if necessary to complete the evaluation. If you agree, MMS also may extend the 120-day period for more than 30 days.

(iv) If MMS must audit sunk costs to evaluate your application, MMS may request that the 120-day evaluation period be tolled from the time you receive notice from MMS until you provide the records necessary to conduct the audit.

(v) If MMS determines during the evaluation period that it cannot evaluate your application because:

(A) Vital information is missing;

(B) The data and information provided in support of the application are inconclusive; or

(C) Of any other valid reason; MMS may request that the 120-day evaluation period be tolled from the time you receive notice from MMS until you provide the needed data, explanations, or revisions.

(e) *When may MMS withdraw approval of an application for royalty relief?*

MMS will withdraw approval of your application for royalty relief if:

(1) You change the type of development system proposed in your approved application (e.g., change from stand-alone to tieback or vice versa);

(2) You fail to start construction of the approved development/production system within two years of the date MMS approved your application—notwithstanding any suspension granted under § 250.10 of this chapter; or

(3)(i) The actual development costs reported in your pre-production report (paragraph (c)(4) of this section) are less than 80 percent of the development costs from the date of application to the date of the pre-production report associated with the most likely scenario described in your approved application. In this case, you may retain 50 percent of the amount of the royalty suspension volume that MMS previously granted.

(ii) If MMS granted you a royalty suspension volume after you requested a redetermination under paragraph (d)(1)(iii) of this section, MMS may withdraw approval of your application for a royalty suspension if your actual development costs in your pre-production report (paragraph (c)(4) of this section) are less than 90 percent of the eligible development costs from the date of application to the date of the pre-production report associated with the most likely scenario described in your approved application.

(iii) If MMS discovers that the actual development costs are less than the amounts specified in paragraphs (e)(3)(i) or (ii) of this section, MMS will withdraw retroactively its approval of the royalty suspension volume. You will owe royalties and interest on all production that was subject to the previously granted royalty suspension.

(4) If MMS determines that you provided false historical or intentionally inaccurate information that was material to MMS in granting royalty relief under this section, MMS will rescind its approval as of the date of the approval. You must pay royalties and late payment interest determined under 30 U.S.C. 1721 and § 218.54 of this chapter on all volumes for which you used the royalty suspension. You also may be subject to penalties under other provisions of law.

(5) If MMS withdraws its approval of a royalty suspension for any of the reasons in paragraphs (e)(1), (2) or (3) of this section, you may apply again for relief under paragraph (b) of this section and § 203.55.

(f) *What happens if MMS fails to accept or reject my application in a timely manner?*

(1) For applications for fields from which no royalties were due on production, other than test production, prior to November 28, 1995, if MMS does not make its determinations on your application within the time period specified in paragraph (c)(1) or (d)(1) of this section, including any applicable extension, you will receive the minimum royalty suspension volumes specified in paragraph (h)(1)(i) of this section.

(2) For PSEP applications, if MMS does not make its determinations on your application within the time period specified in paragraph (c)(1) or (d)(2) of this section, including any applicable extension, you will receive a royalty suspension for the first year of the project's production.

(g) *How do I appeal an MMS decision under 203.53?*

(1) MMS' decision whether to grant deep-water royalty relief and its decision on the size of the royalty suspension volume are final agency actions. You have no right to further administrative review, including Secretarial review, of these decisions. The MMS's decisions are judicially reviewable under section 10(a) of the Administrative Procedure Act (5 U.S.C. 702) only if you file an action within 30 days of the date you receive MMS's decision. MMS's will send its decision to you by certified mail, return receipt requested.

(2)(i) Except as provided in paragraph (g)(2)(ii) of this section, MMS decisions on designating a lease as part of a field are final agency actions.

(ii) If MMS designates your lease as part of a field, within 15 days of such designation you may file a written request with the Director for reconsideration accompanied by a statement of reasons. The Director will respond in writing either affirming or reversing the decision. The Director's decision is the final decision of the Department.

(h) *How does a royalty suspension volume apply to your production?*

This paragraph explains how the royalty suspension volumes in section 302 of the OCS Deep Water Royalty Relief Act, apply to production from PDWL's. For purposes of this paragraph, any volumes of production that are not royalty bearing under the lease or the regulations in this chapter do not count against royalty suspension volumes. Also, for purposes of this paragraph, production includes volumes allocated to a lease under an approved unit agreement. The following provisions apply only to those leases for which the lessee(s) applies for and receives a royalty suspension volume under this section.

(1) For fields from which no royalties were due on production, other than test production, prior to November 28, 1995:

(i) The water depth of a lease is based on the water depth delineations in the ''Royalty Suspension Areas Map'' in effect at the time of your application. If the application for the field includes leases in different water depth categories, the minimum royalty volume associated with the deepest lease applies. The minimum royalty suspension volumes are: (A) 17.5 million barrels of oil equivalent (MMBOE) in 200 to 400 meters of water;

(B) 52.5 MMBOE in 400 to 800 meters of water; and

(C) 87.5 MMBOE in more than 800 meters of water.

(ii) If your PDWL is the only lease on the field, you do not owe royalty on the production from your lease up to the royalty suspension volume MMS granted.

(iii) If a field consists of more than one PDWL, payment of royalties on the PDWLs' production is suspended until their cumulative production equals the royalty suspension volume MMS granted. The royalty suspension volume for each lease equals each lease's actual production (or production allocated under an approved unit agreement) until cumulative production equals the field's royalty suspension volume.

(iv) If a PDWL or an eligible lease, as defined in § 260.102 of this chapter, is added to a field for which MMS has granted a royalty suspension volume under this section, the field's royalty suspension volume will not change. The additional lease may receive a royalty suspension volume only to the extent of its production from the field before the cumulative production from the field equals the royalty suspension volume MMS approved. However, before your PDWL may participate in the royalty suspension volume already granted to the field, you must apply for royalty relief using an abbreviated form available at the Gulf of Mexico OCS Regional Office.

(v) If your PDWL is part of a field that already has a royalty suspension volume for eligible leases under § 260.110 of this chapter, and you apply and qualify for royalty relief under this section, all the leases in the field share a single royalty suspension volume that is the greater of the volume established for the eligible leases under § 260.110 of this chapter or the volume MMS determines under this section.

(2) For a PSEP:

(i) If your PDWL is the only lease included in the project, you do not owe royalty on the incremental production from the project up to the royalty suspension volume MMS granted.

(ii) If the project includes more than one lease, the royalty suspension volume for each lease equals each lease's actual incremental production from the project (or production allocated under an approved unit agreement) until cumulative incremental production for all leases in the project equals the project's royalty suspension volume.

(3) Your lease may receive more than one royalty suspension volume. You may apply for royalty relief under this section for each field that includes your lease, and each field would receive a separate royalty suspension volume if it meets the evaluation criteria of paragraph 203.53(c). You may also apply for relief for a PSEP, even if MMS has already granted a royalty suspension volume to the field that encompasses that project.

(4) You may receive a royalty suspension volume only if your entire lease is west of 87 degrees, 30 minutes West longitude. A field that lies on both sides of this meridian will receive a royalty suspension volume only for those leases lying entirely west of the meridian.

(5) You must measure natural gas production subject to the royalty suspension volume as follows: 5.62 thousand cubic feet of natural gas equals one barrel of oil equivalent, as measured at 15.025 psi, 60 degrees Fahrenheit, and fully saturated.

(6)(i) If in the previous calendar year the arithmetic average of the daily closing prices on the NYMEX for light sweet crude oil exceeds $28.00 per barrel, as adjusted in paragraph (h)(8) of this section, the royalty relief authorized in this section is suspended and any production of oil is subject to royalties at the lease stipulated royalty rate. However, this production counts as part of the established royalty suspension volume. By January 31 of the current calendar year, you must pay the royalty due plus interest, in accordance with 30 U.S.C 1721 and § 218.54 of this chapter, on any volume of oil from the previous year for which you did not pay royalty.

(ii) If the arithmetic average of the daily closing prices on the NYMEX for light sweet crude oil from the previous calendar year exceeds $28.00 per barrel, as adjusted in paragraph (h)(8) of this section, you must pay royalties on all your oil production in the current year. If the arithmetic average of the daily 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 (h)(8) of this section, you are entitled to a refund or credit, with interest, of royalties paid that year on any royalty suspension volume for oil production. You must follow MMS regulations at part 230 of this chapter for receiving refunds or credits.

(7)(i) If in the previous calendar year the arithmetic average of the daily closing prices on the NYMEX for natural gas exceeds $3.50 per million British thermal units, as adjusted in paragraph (h)(8) of this section, the royalty relief authorized in this section is suspended and any production of natural gas is subject to royalties at the lease stipulated royalty rate. However, this production counts as part of the established royalty suspension volume. By January 31 of the current calendar year, you must pay the royalty due plus interest, in accordance with 30 U.S.C 1721 and § 218.54 of this chapter, on any volume of natural gas from the previous year for which you did not pay royalty.

(ii) If the arithmetic average of the daily closing prices on the NYMEX for natural gas for the previous calendar year exceeds $3.50 per million British thermal units, as adjusted in paragraph (h)(8) of this section, you must pay royalties on all your natural gas production in the current year. If the arithmetic average of the daily closing prices on the NYMEX for natural gas for the current calendar year is $3.50 per million British thermal units or less, as adjusted in paragraph (h)(8) of this section, you are entitled to a refund or credit, with interest, of royalties paid that year on any royalty suspension volume for natural gas production. You must follow MMS regulations at part 230 of this chapter for receiving refunds or credits.

(8) Change the prices referred to in paragraphs (h)(6) and (7) of this section during each calendar year after 1994 by the percentage, if any, by which the implicit price deflator for the gross domestic product changed during the preceding calendar year.

(9) A royalty suspension volume will continue until the end of the month in which the cumulative production from the field or PSEP reaches the established royalty suspension volume.

§ 203.54 [Reserved]

§ 203.55 What information is required for the net revenue share royalty relief and deep-water royalty relief application supplemental reports?

(a) You must submit the applicable supplemental reports listed below.

(1) *Administrative information and relief justification.*

All royalty relief applications must contain this report, which must include:

(i) Field name;

(ii) Serial number of leases in the field, names of the lease the titleholders of record, the lease operators, and the identification of whether any lease is part of a unit;

(iii) The API number and location of each well that has been drilled on the field/lease or project;

(iv) Location of any new wells proposed under the terms of the application;

(v) Description of field/lease history;

(vi) Statement that the reserves would not be produced without relief;

(vii) 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;

(viii) Amount of relief needed to make the lease *(NRS royalty relief)*, field *(deep-water royalty relief)*, or project economic;

(ix) Confirmation that MMS approved a DOCD or supplemental DOCD *(NRS expansion of production and deep-water royalty relief application only);* and

(x) A narrative description of the development activities associated with the proposed capital investments and an explanation of proposed timing of the activities and the effect on production *(NRS expansion of production and deep-water royalty relief application only).*

(2) *Net revenue share economic viability report.*

NRS royalty relief applications must contain this report. This report must present cash flow data, including 36 months of historical data and 12 months of projected data, for the following items:

(i) Lease production subject to royalty;

(ii) Total revenues;

(iii) Royalty payments out of production;

(iv) Operating costs;

(v) Transportation and processing costs;

(vi) Capital expenditures (if applicable); and

(vii) Well drilling costs (if applicable).

(3) *Deep-water royalty relief economic viability report.*

This report should demonstrate that the project appears economic without royalties and sunk costs using the model provided by MMS. A company may provide supplemental information, including its own model and model results. This report must include all of the items listed below.

(i) Economic assumptions provided by MMS:

(A) Starting oil and gas prices;
(B) Real price growth;
(C) Real cost growth or decline rate, if any;
(D) Base year;
(E) Range of discount rates; and
(F) Tax rate (for use in determining after-tax sunk costs).
(ii) Projected cash flow analysis (from application date using annual totals and constant dollar values). All costs, gross production, and scheduling must be consistent with the data in the reserve, engineering, production, and cost reports, and the three scenarios (conservative, most likely, optimistic; provided in the various reports must be consistent with each other and the proposed development system. The analysis must show:
(A) Oil/gas production;
(B) Total revenues;
(C) Capital expenditures;
(D) Operating costs;
(E) Transportation costs; and
(F) Before tax net cash flow.
(iii) Discounted values.
(A) Discount rate used (selected from within range provided in MMS guidelines).
(B) Before tax net present value without royalties, overrides, sunk costs, and ineligible costs.
(4) *Deep-water royalty relief cost report.*
Deep-water royalty relief applications must contain this report. Report all actual and projected costs listed in this paragraph in the format detailed in the guidelines.
(i) Sunk costs. This includes all eligible costs, in current dollars and for which documentation is provided, actually incurred subsequent to and including the first discovery well on the field. Sunk costs count on an after-tax, expensed basis, using nominal (current dollar) amounts.
(ii) Delineation and development costs, based on actual costs or current authorization for expenditures. These costs include:
(A) Platform well drilling costs and average depth;
(B) Platform well completion costs;
(C) Subsea well drilling costs and average depth;
(D) Subsea well completion costs;
(E) Production system (platform) costs; and
(F) Flowline fabrication and installation costs.
(iii) Production costs, based on historical costs, engineering estimates, or analogous projects. These costs include:
(A) Operating costs;
(B) Equipment costs; and
(c) Existing royalty overrides (MMS will not use the royalty overrides in its evaluation).
(iv) Transportation costs, based on historical costs, engineering estimates, or analogous projects. These costs include:
(A) Oil and/or gas tariffs from pipeline or tankerage;
(B) Trunkline/tieback line costs; and
(C) Gas plant processing costs for NGL's.
(v) Ineligible costs. These costs include:
(A) Acquisition costs;
(B) Application fees;
(C) Prospective exploration well costs;
(D) Costs associated with obligations existing prior to the application; and
(E) Other ineligible costs listed in § 203.55(b).
(vi) Uncertainty. You must provide a cost scenario consistent with each one of the three field development and production profiles (conservative, most likely, optimistic). Express costs in constant real dollar terms for the base year. You may also express the uncertainty of each cost scenario as a minimum and maximum percentage of the base value.
(vii) Scheduling. Provide costs on an annual basis (in real dollars) for each of the categories in paragraphs (a)(4)(i) through (a)(4)(vi) of this section.
(viii) Abandonment. Provide the costs to plug and abandon wells and to remove production systems for which costs have not been incurred at the time of application.
(ix) Pre-production report. You must file a pre-production report 60 days before the start of the production subject to an approved royalty suspension. For each of the cost categories in the deep-water royalty relief cost report, you must include actual costs up to the date when the pre-production report is submitted. Retain supporting records for these costs and make them available to MMS upon request.
(5) *Geologic and geophysical report.*
Deep-water royalty relief and NRS production expansion proposal applications must contain this report. This report must include all of the items listed below.
(i) Seismic data:
(A) Non-interpreted 2D/3D survey lines (8mm tape) (SEGY format or IES format);
(B) Interpreted 2D/3D seismic survey lines identifying all known and prospective pay horizons, wells, and fault cuts;
(C) Digital velocity surveys in format of LTL 10/1/90;
(D) Plat map of ''shot points;'' and
(E) ''Time slices'' of potential horizons.
(ii) Well data.
(A) Hard copies of all well logs.
(*1*) One-inch electric log must show:
(*i*) pay zones and pay counts; and
(*ii*) lithologic and paleo correlation markers at least every 500 ft.
(*2*) One-inch type log must show missing sections from other logs where faulting occurs.
(*3*) Five-inch electric log must show:
(*i*) pay zones and pay counts; and
(*ii*) labeled points used in establishing Ro and Rt.
(*4*) Five-inch porosity logs must show:
(*i*) pay zones and pay counts; and
(*ii*) labeled points used in establishing reservoir porosity or labeled points showing values used in calculating reservoir porosity such as bulky density or transit time.
(B) Digital copies of all well logs spudded before December 1, 1995.
(C) Core data, if available.
(D) Well correlation sections.
(E) Pressure data.
(F) Production test results.
(G) PVT analysis, if available.
(iii) Map interpretations. For each reservoir included in the application, you must submit:
(A) Structure maps and top and base of sand maps showing well and seismic shot point locations;
(B) Isopach maps for net sand, net oil, net gas, all with well locations;
(C) Maps indicating well surface and bottom hole locations, location of development facilities, and shot points; and
(D) Identification of reservoirs not contemplated for development.
(iv) Reservoir data. For each reservoir included in the application, you must identify and submit:
(A) Oil and/or gas reserve/resource distribution;
(B) Probability of reservoir occurrence with hydrocarbons;
(C) Probability the hydrocarbon in the reservoir is oil, and the probability it is gas;
(D) Distributions for the parameters used to estimate the resources, i.e. acre, net thickness, recovery, porosity, salt water saturation, formation volume factor;
(E) Aggregated BOE reserve/resource for the field;
(F) Gas/oil ratio distribution for each reservoir;
(G) Yield distribution for each gas reservoir;
(H) Description of anticipated crude quality (e.g., gravity); and
(I) Points on the aggregated reserve/resource distribution used for the determination of the three (conservative, most likely, optimistic) production profiles specified in the production report.

(6) *Production report.* Deep-water royalty relief and NRS production expansion proposal applications must contain this report, which must include all of the items listed below.

(i) Production profile. Submit actual and projected (BOE) production by year for each of the following products: oil, condensate, gas, and associated gas.

(ii) Uncertainty *(deep-water royalty relief only).* Submit three production profiles as described in paragraph (a)(6)(i) of this section. Each one must be consistent with a specific point on the aggregated reserve/resource distribution and must represent a conservative, most likely, and an optimistic case.

(iii) Production drive mechanisms for each reservoir.

(iv) Quality adjustments to prices for gravity, sulfur, etc.

(7) *Engineering report.*

Deep-water royalty relief and NRS production expansion proposal applications must contain this report. However, NRS expanded production applications should submit this information only as it relates to the planned development. This report must include all of the items listed below.

(i) Development concept:

(A) Tension leg platform, fixed, floater type, subsea tieback, etc.; and

(B) Construction schedule.

(ii) Planned wells:

(A) Number of wells planned;

(B) Type of well (platform, subsea, vertical, deviated, horizontal);

(C) Well depth;

(D) Drilling schedule;

(E) Completion description (single, dual, horizontal, etc.); and

(F) Completion schedule.

(iii) Production system equipment:

(A) Production capacity for oil and gas and a description of its limiting component(s);

(B) Unusual problems (low gravity, high sulfur content, etc.);

(C) Subsea structures;

(D) Flowlines; and

(E) Production system installation schedule.

(iv) Multi-phase development plans;

(A) Conceptual basis for developing in phases and goals/milestones required for commencing subsequent phases; and

(B) Justification for the exclusion of reservoirs not contemplated for development.

(v) Uncertainty. Submit schedules for development consistent with each of the three field production profiles (conservative, most likely, optimistic) provided in the production report.

(b) Ineligible costs. MMS will not include certain costs in making its royalty relief determinations. These include, but are not limited to:

(1) Costs incurred before first discovery on the field;

(2) Cash bonuses;

(3) Royalty relief application fees;

(4) Lease rentals, royalties, and net profit share and net revenue share payments;

(5) Legal expenses;

(6) Damages and losses;

(7) Taxes;

(8) Interest or finance charges;

(9) Fines or penalties;

(10) Designated well costs, including prospective exploration and delineation costs; and

(11) Costs associated with prior existing obligations (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 the application).

(c) The applicant or the applicant's authorized representative must certify that all information submitted in an application or a pre-production report is accurate and complete. The application or pre-production report must be accompanied by a report prepared by an independent certified public accountant (CPA) expressing an unqualified opinion on the accuracy of the actual historical financial information presented in the application or pre-production report and that the presentation of data and information conforms to the MMS guidelines. The applicant will make the independent CPA available to the MMS to respond to questions which may arise regarding the evaluation of the historical information. This requirement does not limit the MMS's ability to conduct further review of the applicant's records to support the historical financial information included in the application.

§ 203.56 Recovery of application processing costs.

When you submit an application for royalty relief, you must include a payment to reimburse MMS for the costs it incurs in processing your application. The MMS will establish in a Notice to Lessees a schedule that will specify the fees that must be paid for each of the different types of royalty relief applications. Regional Directors will periodically update the fee schedule to reflect changes in MMS costs as well as to provide other information necessary for the administration of our royalty relief program.

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DEPARTMENT OF THE TREASURY

Secret Service

31 CFR Part 411

[1505–AA69]

Color Illustrations of U.S. Currency

AGENCY: Secret Service, Treasury.

ACTION: Final rule.

SUMMARY: Pursuant to the Counterfeit Deterrence Act of 1992, the Secret Service permits color illustrations of United States currency provided such illustrations are consistent with the requirements set out in this final rule. Prior to the issuance of this rule, color illustrations of U.S. currency were not permitted.

EFFECTIVE DATE: May 31, 1996.

FOR FURTHER INFORMATION CONTACT: Mark Mulligan, Attorney/Advisor, Office of Chief Counsel, U.S. Secret Service, 1800 G Street, N.W., Room 842, Washington, D.C. 20223, (202) 435–5771.

SUPPLEMENTARY INFORMATION: On June 26, 1995 (60 FR 32929), the Secret Service proposed to amend title 31, chapter IV of the Code of Federal Regulations by adding part 411 which would permit color illustrations of U.S. currency. At the time this proposal was issued, illustrations of U.S. currency were only permitted provided the illustration was in black and white and was of a size less than three-fourths or more than one and one-half, in linear dimension, of each part so illustrated, and provided the negatives and plates used in making the illustration were destroyed after their final use. 18 U.S.C. 504. Color illustrations of U.S. currency were not permitted.

Interested parties were invited to participate in the rulemaking proceeding by submitting written comments on the proposal. Five comments were received. The Secret Service carefully reviewed and evaluated these comments. In considering these comments, the Secret Service carefully weighed the recommendations and comments with the federal government's compelling interest of preventing the counterfeiting of U.S. currency.

Specifically, all the commentators to some extent questioned the need for and practicality of the requirement that the term ''non-negotiable'' be prominently and conspicuously placed across the center portion of any color illustration. After careful consideration, the Secret Service has decided to amend its proposal by removing the requirement