Rate set	For plans with a valuation date		Immediate annuity rate (percent)	Deferred annuities (percent)				
	On or after	Before		i_1	i_2	i_3	n_1	n_2
*	*	*	*	*	*	*		
100	2–1–02	3–1–02	4.75	4.00	4.00	4.00	7	8

3. In appendix C to part 4022, Rate Set 100, as set forth below, is added to the table. (The introductory text of the table is omitted.)

Appendix C to Part 4022—Lump Sum Interest Rates For Private-Sector Payments

* * * * *

Rate set	For plans with a valuation date		Immediate annuity rate (percent)	Deferred annuities (percent)				
	On or after	Before		i_1	i_2	i_3	n_1	n_2
*	*	*	*	*	*	*		
100	2–1–02	3–1–02	4.75	4.00	4.00	4.00	7	8

PART 4044—ALLOCATION OF ASSETS IN SINGLE-EMPLOYER PLANS

4. The authority citation for part 4044 continues to read as follows:

Authority: 29 U.S.C. 1301(a), 1302(b)(3), 1341, 1344, 1362.

5. In appendix B to part 4044, a new entry, as set forth below, is added to the table. (The introductory text of the table is omitted.)

Appendix B to Part 4044—Interest Rates Used to Value Benefits

* * * * *

For valuation dates occurring in the month—	The values of i_t are:					
	i_t	for t =	i_t	for t =	i_t	for t =
*	*	*	*	*	*	*
February 2002	.0580	1–25	.0425	>25	N/A	N/A

Issued in Washington, DC, on this 10th day of January, 2002.

Steven A. Kandarian,

Executive Director, Pension Benefit Guaranty Corporation.

[FR Doc. 02–1136 Filed 1–14–02; 8:45 am]

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DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 203

RIN 1010–AC71

Relief or Reduction in Royalty Rates—Deep Water Royalty Relief for OCS Oil and Gas Leases Issued After 2000

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: This rule revises regulations on royalty relief for oil and gas producers on the Outer Continental Shelf (OCS). It provides for suspension or reduction of royalty on a case-by-case basis for certain additional categories of OCS leases under part 203 of this title. Also, it identifies circumstances when we may consider royalty relief apart from our end-of-life and deepwater royalty relief (DWRR) programs.

DATES: This final rule is effective February 14, 2002.

FOR FURTHER INFORMATION CONTACT: Marshall Rose, Economics Division, at (703) 787–1536.

SUPPLEMENTARY INFORMATION: On November 16, 2000, we published a proposed rule in the **Federal Register** (65 FR 69259). For leases that lie in water 200 meters or deeper in the Gulf of Mexico (GOM) wholly west of 87 degrees, 30 minutes West longitude and issued after November 2000, it provided a process to apply for supplemental royalty relief. Also, it proposed to modify the relief qualification process. Some proposed modifications apply only to leases issued after November 2000 (newly issued leases) while others apply both to leases issued before the DWRR Act (pre-Act leases) and to newly issued leases. These proposed modifications sought to combine more opportunity, certainty, and flexibility for applicants with a royalty relief determination process more focused on future costs and benefits. We requested comments on these proposed changes.

We also finalized in the **Federal Register** on February 23, 2001 (66 FR 11512) regulations on the way we implement OCS leasing incentives on newly issued leases. The opportunity for newly issued leases to qualify for royalty relief that supplements lease-term incentives when we issued them is an important part of the change in these incentives.

Several comments on the proposed rulemaking addressed the changed leasing incentives and the modifications to the royalty relief qualification process. This final rule makes changes from the proposed rule in response to comments we received. The most significant changes relate to sunk costs and the timing of our evaluations.

As sunk costs, which we use to determine only qualification, not the volume suspension amount, we proposed to count only the cost of the project's first discovery well. Comments convinced us that a more expansive definition was appropriate. This final rule allows the costs of the first project discovery well on each lease. We believe this provides the proper balance between the need to encourage exploration of marginal future prospects and the lack of any role sunk costs have in determining economic viability after a discovery.

With respect to timing, we proposed to retain the 180-day period for our review of royalty relief requests for projects. Comments indicated a strong desire for a shorter period. Efficiencies from evaluating expansion or development projects, instead of fields (as required for applications involving pre-Act leases), can reduce our average evaluation time by 1 month. Hence, this final rule lowers our timeframe for evaluating development or expansion projects, but not for fields, from 180 to 150 days.

Response to Comments

We received a joint comment from six oil and gas industry associations, and separate comments from one of those associations and from five oil and gas companies in response to our request for written comments on our proposed rulemaking. Also, two public workshops raised questions on the proposed rule. Copies of all the written comments we received are available on our Web site at *http://www.mms.gov/federalregister/PublicComments/rulecomm.htm.*

We analyzed all comments and workshop questions and revised the final language based on many of them. The main changes from the proposed rule involve a more expansive definition of allowable sunk cost, a shorter evaluation period, and more specificity on several subjective terms (significant expansion, most likely resource size, most efficient development system).

Two changes from the proposed version of this rule make the final version consistent with changes made in the companion rule on OCS leasing incentives. Finally, we note provisions where we adjusted the language to clarify but not change the meaning from the proposed rule.

Supplementary Relief

One general comment objected to reliance on discretionary royalty relief because of administrative burdens and increased costs to industry.

Response: We agree that the discretionary royalty relief program will become more important when leases issued after 2000 represent significant amounts of acreage and discoveries in the deep water GOM. But it will be many years before post-2000 leases play a significant role in deepwater development. As we explained in earlier **Federal Register** notices on continuing royalty relief in deep water, most of the prospective deepwater tracts now have access to the royalty suspension volumes prescribed by the DWRR Act. Some 3,400 eligible leases already have the potential to receive royalty suspension automatically. Another nearly 1,700 pre-Act leases may qualify for royalty relief under discretionary relief regulations that have been in place for several years. The currently leased acreage—eligible and pre-Act leases—represents almost half of the deep water GOM acreage. These handpicked opportunities, which industry believes have the best hydrocarbon prospects, will occupy the available exploration and delineation capability in the GOM for many years. Much of the new production in deep water over the next decade or so may be royalty-free. Hence, we anticipate that the overall royalty expenses for deepwater oil and gas production will decrease for some time completely independent of future terms and conditions on newly offered tracts.

We expect to process applications more quickly and efficiently as we become more experienced in handling them. These final discretionary relief regulations follow the directive in the DWRR Act to consider granting royalty suspension only in those circumstances when otherwise developable production would be uneconomic because of normal royalty obligations. Thus only some, not all, leases should be concerned with or have a need for the discretionary royalty relief program. Further, to encourage development, we make the uneconomic determination not after production occurs, but before, using forecasts of many variables. The determination unavoidably involves the collection, analysis, and evaluation of detailed information. Questions about possible inconsistencies or options in a specific development proposal often only become apparent during the review process. Evaluation then sometimes requires additional information. Computing and documenting forecasts tied to the circumstances of a specific project proposal may appear cumbersome at times, but a sound determination requires that we understand the key assumptions and risks in the applicant's proposed project.

The comment most relevant to our request for paperwork reduction suggestions was the acknowledgment that ''the majority of the information requested by MMS is necessary * * * for a comprehensive review of a proposed project.'' We have added language to encourage potential applicants to meet with MMS prior to filing an application to identify unusual elements in the project and for guidance on application format, content, and our evaluation perspective. *See* § 203.62(c).

Several proposed changes we finalized expedite the evaluation process by making it less burdensome. We designate the applicant's project and the reservoirs targeted by the proposed project as the application unit rather than the entire field, as in the current DWRR program. Thus the applicant no longer must involve adjacent lessees in the application, and we no longer need to speculate about additional resources that may affect field economics. Also, this change reduces the need for us to evaluate alternative field development scenarios. Other changes should reduce the burden on both pre-Act lease applicants and new lease applicants by giving them more flexibility to adjust to changing conditions. We extend the time period for successful applicants to commit to development and allow reapplication in a wider range of circumstances. Potential applicants will become more comfortable with our application and evaluation process by the time the burden for DWRR shifts more to the discretionary royalty relief program.

Sunk Costs

A number of comments expressed concerns about the limited allowance of sunk costs to evaluate the economics of a proposed project.

Response: Our proposed change in allowable sunk costs—from all costs of and after discovery to only those of the discovery well—received the most comments from industry. That reaction may indicate that limiting allowable sunk costs is perceived as the most important proposed change to the discretionary royalty relief rules. The size of sunk costs has been the main reason for royalty relief qualification in our determinations to date. We proposed no change to the treatment of sunk costs in applications from non-producing pre-Act leases to keep within the DWRR Act. Also, we proposed to add for the first time some sunk costs to our evaluation of expansion projects. Nonetheless, in light of its perceived and past importance, we expand our definition of allowable sunk costs for applications from leases issued after 2000 and for expansion projects on pre-Act leases.

One workshop comment suggested that the definition of allowable sunk costs include the cost of the first well on each lease that discovers hydrocarbons in the reservoirs included in the application. We adopt this new definition because it includes the most important and readily identifiable delineation costs on a project.

This more expansive definition of sunk costs may encourage more development and more exploration than otherwise. Historic costs theoretically do not affect the expected profitability of a particular project, as measured from the perspective of its application date. But, their treatment can influence decisions on the timing and magnitude of pre-application exploration, drilling, and appraisal. Using sunk costs in an evaluation makes qualification for discretionary royalty relief more likely. The more likely that a prospect of a given size will qualify for relief, the larger the expected value of that prospect. And, the higher the expected payoff from drilling, the more and sooner drilling will take place.

We choose to rely on supplemental discretionary royalty relief to concentrate royalty savings on prospects that show a need for it. General lease sale incentives disperse royalty relief over all lease prospects regardless of whether they need development assistance. In a system where supplemental royalty relief plays a large role in the incentive program, it may not be appropriate to narrowly define qualification for the supplemental relief based on theoretical rather than practical considerations.

While an expansive consideration of sunk costs is in order, we believe the broad definition applicable to pre-Act leases is not appropriate for newer leases. The object of the new supplemental royalty relief program is a specific and fully identified project, rather than a whole, often incompletely identified, field. A royalty relief determination on a field with pre-Act leases requires evaluation of all resources that may ultimately be assigned to that field and of associated development options. The broad field determination provides a basis for considering all possible resources and thus the sunk costs for a wide range of appraisal activities. Project royalty relief determination, on the other hand, is confined to the reservoirs identified in the application. Relief qualification need not consider alternative development options or potential production from other reservoirs. So, fewer post-discovery expenditures are relevant to a project application. Therefore, we will count the costs of only the discovery well for the project on each lease participating in an application for other than an authorized field. To clarify the revision as well as the distinction, we separate the definition of sunk costs for authorized fields from the definition of sunk costs for development and expansion projects and move identification of the critical elements to the definitions from the cost report description in § 203.89 (a). *See* changes in §§ 203.0 and 203.68.

We continue to count allowable sunk costs on an after-tax, nominal basis. A company recoups part of exploratory drilling costs through a deduction from taxable income. Crediting all the pre-tax costs to royalty relief qualification would substantially raise the benefit accorded sunk costs. Adjusting sunk costs for inflation could reward applicants that delay applying for royalty relief.

Other Comments

The written comments and workshop questions raised a number of specific or technical issues. The following table summarizes and responds to each of those issues. We arranged the table according to the section in the rule to which the comment relates. The last part of the table addresses comments on information collection under the Paperwork Reduction Act.

CFR section	Industry comments and questions	MMS response
203.0, 203.2, and 203.4	Delete the word ''significant'' from the definitions of an expansion project and of new production because it is too subjective when left to the discretion of the application process.	Accommodating change. The DWRR Act used the word ''significant'' to direct relief to projects that add new resources, not those that simply extend recovery of reservoirs already in production. We delete ''significant'' from the definition of ''new production'' and clarify in the definition of ''expansion project,'' that it refers to one or more new wells drilled into a reservoir that has not previously produced. Also, we modify the definition of ''new production'' accordingly.
203.0 and 203.60	Don't limit development projects that can apply for deepwater royalty suspension to those on leases west of 87 degrees 30 minutes West longitude in the GOM.	No change. The DWRR Act gives authority to grant royalty relief to existing non-producing leases, but only those in this part of the GOM. We may issue new leases with a variety of terms, including royalty suspension, in other parts of the OCS.
203.0, 203.4, 203.70, and 203.81.	Eliminate from the definition of fabrication a requirement for a requirement for a letter from the fabricator certifying start of continuous construction because it is an unnecessary and redundant burden.	No change. The legitimacy of the royalty relief qualification determination depends on prompt development. We see value in having a third party witness an event that has such important to an applicant. The down payment and contract alone may not ensue that the operator has actually committed to construction that will not be interrupted after it has started. The notice could be just a copy of whatever normal notification the applicant gets from the fabricator that construction has started on its system, with the intent to continued without interruption.

CFR section	Industry comments and questions	MMS response
203.0, 203.68, and 203.89 ...	Redefine sunk costs as all of the inflation adjusted before-tax costs of, and after, discovery up until the application.	Accommodating change. We have enlarged the scope of sun costs from the proposed rule. But historic costs have questionable relevance to proceeding with development of the project in the application. Also, many such costs have already been recovered through tax deductions and subsequent savings. The expansion in the definition is limited to discovery well costs for one eligible well per lease.
203.0, 203.68, and 203.89 ...	Does MMS want to receive applications before delineation wells are drilled which help in the decision on the development approach.	We want a reliable application. The applicant is the only one in a position to balance the costs and benefits of incremental delineation. Performance conditions help encourage a proper balance—enough data in hand for the applicant to commit to a few key decisions but not to detailed development plans.
203.2 and 203.80	Delete the word ''significantly'' word from the characterization of how much production must increase as a result of royalty relief because it is too subjective.	Accommodating change. We delete the word from the end-of-life relief cell in the table in § 203.2, but as with deepwater expansion projects, we look for a minimum production increase for consideration of royalty relief apart from our formal programs. Relief generally must make production for an extra year profitable.
203.4, 203.69 and 203.76	Clarify the resource number used as a basis for determining the minimum royalty suspension volume.	Change. By ''most likely resource size'' we mean the median value of the estimated distribution of known recoverable resources from reservoirs included in the application for the project. The final rule adopts this more precise terminology.
203.4	Indicate that price thresholds will be specified in the Notice of Sale as well as in the lease document.	Change. We make clear in subsections (e) and (f) that price thresholds and minimum suspension volumes may be set in the Notice of Sale or the regulations or in the lease.
203.62	Encourage pre-application meetings between the MMS regional office and a prospective applicant.	Change. Such a meeting can save time both in preparing an application and in avoiding omissions that delay the evaluation process.
203.63	Clarify that neither a development nor expansion project must include all leases in its field.	Change. We also make the same clarification that ''project'' means development either expansion project or development project in §§ 203.64, 203.65, 203.67, 203.68, and 203.69.
203.65	Change the evaluation deadline from 180 to 120 days for a first application and from 120 to 90 for a redetermination.	Accommodating change. We reduce the evaluation period for development projects and expansion projects to no more than 150 days after certifying an application and application complete. For field evaluations involving pre-Act leases, the 180-day deadline continues because we must consider potential development of all resources on the field, whether or not they are identified in the application.
203.69	If a participating lease doesn't have or propose, a well into the reservoirs included in the application, does MMS include in the minimum suspension volume calculation the royalty suspension volume with which the lease was originally issued?	A lessee can join the application with evidence that the reservoir(s) targeted by the project occur on its lease. However, a lease without enough of the project's resources to justify a well cannot include its automatic royalty suspension volume in the minimum set for the project. Nevertheless, we will count its estimated resources in the project evaluation and in the increment to the minimum royalty suspension volume based on the median of the distribution of resources.
203.69 and 203.76	Does a lease retain the royalty suspension volume with which it was originally issued if it applies and qualifies for project relief but then violates a performance condition.	Since the application qualification included consideration of the pre-existing royalty suspension on the lease, it retains that relief if we withdraw approval of its application. We don't want to discourage early-stage applications when some development decisions have not yet been made.
203.71	If a lease is added to a project after approval of an application, does the added lease have to give up its automatic relief to be part of the project.	If the reservoir(s) targeted by the development project extend to a post-2000 lease, that lessee has an option. The lessee may file a short form to share the project's remaining royalty suspension volume or simply retain its automatic royalty suspension volume for use with this or other reservoirs on its lease. If it files the short form to share in the project relief, it gives up its automatic relief volume.
203.74	A phrase is missing in the description of the new event that enables a redetermination.	Accommodating change. We rewrote to clarify that the new technology must improve the profitability, under equivalent market conditions, of the field or specified set of reservoirs relative to the development system proposed in the prior application.

CFR section	Industry comments and questions	MMS response
203.76	Allow retention of half of the royalty suspension volume, not the smaller of that or the most likely resource size, when costs are overestimated in the application.	No change. We made the modification in the proposed rule because otherwise small fields face no disadvantage for overestimating their costs in a royalty relief application.
203.78	If the price threshold suspends relief when prices rise too much above expected levels, why not augment initial royalty suspension volume if prices fall too much below expected levels.	We provide a reasonable inducement to make a project economic under expected market conditions. This is the focus of our program. Subsequent deviations in these conditions during periods of production and potential relief from royalties may change profitability, but are not likely to affect project viability. Should prices decline once production begins, the lessee can pursue our other royalty relief programs. These programs serve as a proxy for predetermined increases in royalty suspension volume for a price decline.
203.80	Allow the costs of pre-existing facilities that help justify a royalty relief application to be off lease.	Change. Off-lease facilities tied back to the lease may help justify a relief application to the extent that preservation of these pre-existing facilities depends on continued application to be production from the lease applying for royalty relief. We will include only a logically allocable share of costs from the off-lease facilities.
Information Collection Questions.	(a) Under the current evaluation process, acknowledgement that the majority of the information requested in an application is necessary.	(a)We have not identified an alternative evaluation process suitable for use with an irrevocable determination such as royalty relief. Past applicants and industry committees have not yet identified any unnecessary information elements.
	(b) Contact past applicants to very estimates of the time it takes to fill out an application.	(b) We welcomed comments from past applicants to help develop our current estimates of the burden.
	(c) Standardize the various application reports that must be submitted or generate a set of generic example reports as guides for future applicants.	(c) We have standardized reports as much as we can, and we do invite pre-application consultation on format and content. We do not share past applications even in generalized form so as to avoid possibly exposing proprietary information. We already offer an example with the model that combines the information in these reports. That should clarify many questions about technical details such as units of measure.
	(d) MMS mail server limits make it impractical to submit the original application electronically, but subsequent information could usually be submitted by e-mail.	(d) We are implementing the Government Paperwork Elimination Act (GPEA). The Act calls for providing an electronic processing option when practical for information we collect. Royalty relief applications are under review in our GPEA implementation information program. We do currently accept extra copies and additional information by electronic or fax means.

Changes for Consistency and Clarity

We make two changes in this rule on discretionary royalty relief to make it consistent with our rule on OCS leasing incentives published on February 23, 2001 (66 FR 11512). Also, we use definitions for ''eligible,'' ''pre-Act,'' and ''royalty suspension'' leases in this rule that are identical to those in the leasing incentive rule.

The leasing incentive rule includes the option to offer royalty incentives for a value of production or for a time period as well as for a volume of production. The definition of Royalty Suspension (RS) leases in § 203.0 now indicates that the royalty suspension for an RS lease need not be in the form of a volume. So, one or more leases on a project applying for additional royalty relief may have automatic suspensions in a form other than volume. Section 203.69(b) now indicates that should this situation arise, we will use the data in your application, after any adjustments we make during our evaluation, to convert royalty relief already available to a common basis expressed in volume, and carry out the evaluation accordingly. Any approval would be expressed solely in terms of volume.

The leasing incentive rule also includes a provision in § 260.122(b)(2) for paying royalties, due as a result of the price threshold being exceeded, no later than 90 days after the end of the period for which royalty is owed. That deadline is shorter than the 120-day interval to April 30 now specified in § 203.78(a)(1) and (b)(1). To avoid confusion, we changed § 203.78 to be consistent with § 260.122. The 90-day time lag is longer than the 30-day time lag for payment of normal royalty under § 218.50 because we must calculate inflation adjustments in the case of price thresholds. The actual NYMEX price can be calculated immediately after the end of the period specified, but the final value for the implicit price deflator for the gross domestic product is not generally available for several months after the end of the period.

In several places, we modified the language in the proposed rule to make its meaning clearer to the reader.

CFR section	Clarification
203.0	We enhance definitions to: (1) State that development or expansion projects must be in water at least 200 meters deep, (2) Declare that redetermination is a procedure we conduct under certain conditions at your request, and (3) Illustrate some elements of eligible sunk costs incurred before a discovery.
203.2	We replace ''when'' with ''how'' in the title question. Unlike ''expansion project'' ''authorized field'' and ''development project,'' ''end-of-life lease'' is a term defined here but not in § 203.0. We drop reference to significant capital investment by an expansion project because that is not a separate requirement for an expansion project on a lease issued after 2000. The flexibility of royalty relief apart from our formal programs may involve changes in the form of the royalty as well as in its size or duration.
203.4	We more carefully explain how to interpret the tables summarizing our royalty relief programs. End-of-Life relief is now withdrawn only when the effective royalty rate has prevailed for 12 consecutive months. We drop reference to charging more than the original lease royalty rate after the suspension volume has been produced.
203.4 and 203.69	The various forms of royalty relief we grant are subject to certain conditions set out in regulations or approval letters. We rephrase the way one determines cumulative production.
203.60	We reversed the phrases in the lead sentence. We stipulate that pre-Act leases, but not leases issued after 2000, must have been assigned to a field as well as have a discovery prior to applying for royalty suspension.
203.63	You must, rather than may, submit data you have on leases that you believe may become part of your authorized field in the future.
203.64	Only one application may be filed on a development project designed to produce a specific set of reservoirs.
203.66	We make explicit that prescribed evaluation deadlines may be extended and rephrase the table lead-in sentence. We clarify that a penalty suspension for our late determination applies to the first production from a development project.
203.68	We do not consider sunk costs when we determine whether a project is economic should it never have to pay royalties.
203.69	We substitute the new name for the publication that gives the water depth of each lease.
203.71	Eligible leases as well as RS leases retain the royalty suspension volumes with which they start an application process, even if we reject an application that requests more relief on a field or development project. Applying leases are ones that participate in the application for royalty relief. Leases issued without a royalty suspension volume do not share the relief for a field with an automatic royalty suspension volume. We drop reference to the impossible situation of adding a lease before you submit an application from the paragraph (a) that describes the effect of adding a lease to an authorized field after we have approved royalty relief.
203.74	The discussion in the sub-elements of (c) explains a procedure for calculating prices, not determining eligibility for a reconsideration of a royalty relief determination.
203.78	Different price thresholds may apply to different leases on the same field, development project, or expansion project. Different price thresholds could occur if the leases were issued at different times. And, only the base oil and gas price thresholds for pre-Act leases are adjusted from 1994 forward. Post-2000 lease price thresholds are adjusted forward from other periods as specified in their Notice of Sale or lease documents.
203.80	We no longer formally refer to royalty relief apart from our end-of-life or deepwater programs as ''special''.
203.83	We require a well number and status as part of the Administrative Information Report.
203.89	We drop restatement of the definition of sunk costs. We stick to identifying the measurement rather than the concept of sunk costs by, for example, stating that nominal dollars mean dollars not adjusted for inflation.

Summary of Changes

The following table summarizes the changes this rule makes to the existing structure of our DWRR program.

MODIFICATIONS TO DWRR APPLICATIONS

Element	Current and continuing program (applies to pre-act leases)	Changes (applies to post-2000 deep water leases only)
Eligibility (Central, Western, and western part of Eastern Gulf of Mexico).	Leases in 200m or more water depth issued before 1996.	Leases in 200m or more water depth issued after 2000.
Royalty-free production can come from	Any production from the field until cumulative recovery volume equals the suspension volume.	Only production from resources identified in the application until cumulative production equals the suspension volume.

MODIFICATIONS TO DWRR APPLICATIONS—Continued

Element	Current and continuing program (applies to pre-act leases)	Changes (applies to post-2000 deep water leases only)
Minimum suspension volume for non-producing leases.	For fields that did not produce before the Act, matches eligible lease suspension volumes (17.5, 52.5, 87.5 MMBOE) in equivalent water depths.	For development projects, matches volumes designated in sale and lease documents for various water depths of 200m or greater plus 10 percent of the median value of the distribution of resources.
Credit for sunk costs in application	For fields with pre-Act leases that did not produce before the application, after-tax costs of and after discovery well used in qualification.	For development projects, after-tax eligible costs of the discovery well for the project on each participating lease.
Evaluation deadline for non-producing leases	180 days for first determination, 120 days for a redetermination.	150 days for first determination, 120 days for a redetermination.
Threshold oil and gas price levels for lifting relief.	Statute sets threshold price for light sweet crude oil and natural gas.	Original lease terms or Notice of Sale set threshold price for light sweet crude oil and natural gas.

Element	Current and discontinuing program (applies to pre-act leases)	Changes (applies to pre-act and post-2000 deep water leases)
Discount rate used in evaluation	Same rate used on viability and profitability tests, applicant chooses between 10% and 15%.	Use 10% on viability test, applicant chooses rate between 10% and 15% for profitability test.
Redetermination of field qualification or volume by MMS.	Available for new well or seismic data, 25% lower prices, or 20% higher cost.	Available anytime after relief relinquished or withdrawn. Otherwise, for new well or seismic data, 25% lower prices, 20% higher cost, or more efficient development system.
Deadline for starting fabrication	Within 1 year of approval, extendable for up to 1 year.	Within 18 months of approval, extendable for up to 6 months.
Correction for overestimating cost by 20% or more.	Retain only half of suspension volume granted.	Retain only half of smaller of the granted suspension volume *or* the median of the distribution of resources.
Minimum suspension volume for expansion project.	None	10 percent of median of the distribution of resources.
Evaluation deadline for expansion project	180 days for first determination, 120 days for a redetermination.	150 days for first determination, 120 days for a redetermination.
Credit for sunk costs in application for expansion project.	None	After-tax eligible costs of the discovery well for the project on each participating lease.

Procedural Matters

Regulatory Planning and Review (Executive Order 12866)

The rule is a significant regulatory action under Executive Order 12866, and subject to review by the Office of Management and Budget (OMB).

a. This rule will not have an annual economic effect of $100 million or adversely affect an economic sector, productivity, jobs, the environment, or other units of government. This action describes how new deepwater leases may qualify for royalty suspensions and the circumstances under which we might grant royalty relief. Historically, we have received only a limited number of applications for royalty relief. Based upon our experience, only a small number of leases will qualify for royalty relief in any one year. The only field that has gone into production after royalty relief approval would have avoided about $7 million in royalty payments in its first year of production, had prices not exceeded the price threshold for discontinuing royalty relief. The royalty suspension options in this proposal will encourage new production from a few marginal leases, because they will sustain profitability at lower prices than they would without the relief. Royalty suspension volumes act as an incentive to production, and likely will have a beneficial effect on the offshore oil industry, domestic oil and gas supplies, and jobs. This program should increase OCS production by making production from marginal fields more profitable.

b. This rule does not create inconsistencies with other agencies' actions because it preserves the concepts and requirements from the existing rule.

c. This rule is an administrative change that will not affect current entitlements, grants, user fees, loan programs, or their recipients. This rule has no effect on these programs or rights of the programs' recipients.

d. This rule does not raise any novel legal issues, but does raise policy issues. The rule extends and supplements the existing DWRR rule. It describes conditions under which lessees have the opportunity to apply for and acquire royalty relief on post-2000 deepwater leases. Also, it eases some conditions under which lessees of pre-Act leases may seek to obtain royalty relief. In addition, the rule describes circumstances not specified in our previous regulations under which lessees may apply for royalty relief. All of these changes are consistent with the basic philosophy in the current rule of granting relief only when applicants show it is economically necessary for development.

Regulatory Flexibility (RF) Act

The Department certifies that this document will not have a significant economic effect on a substantial number of small entities under the RF Act (5 U.S.C. 601 *et seq.*). The provisions of this rule will not have a significant adverse economic effect on offshore lessees and operators, including those that are classified as small businesses. The rule extends the benefit of discretionary royalty relief to certain OCS leases issued after November 2000 that qualify as marginally uneconomic. In any single year, we are likely to receive only a small number of royalty relief applications, which limits the number of entities the rule may affect. Based on past experience, we expect to receive between one and two applications a year for DWRR. Also, because firms initiate applications, they have the ability to avoid any adverse effects they foresee. As suggested below, the new provisions should actually lower the cost to those who choose to take advantage of the benefit offered by this regulation. An RF analysis is not required. A Small Entity Compliance Guide is not required.

Companies that extract oil, gas, or natural gas liquids or are otherwise in oil and gas exploration and development activities acquire the vast majority of leases offered at OCS lease sales and will be most affected by this rule. The Small Business Administration (SBA) defines a small business as having:

- Annual revenues of $5 million or less for exploration service and field service companies.
- Fewer than 500 employees for drilling companies and for companies that extract oil, gas, or natural gas liquids.

Under the North American Industry Classification System Code 211111, Crude Petroleum and Natural Gas Extraction, we estimate that a total of 1,380 firms drill oil and gas wells either onshore and/or offshore. Of these, approximately 130 companies are offshore lessees/operators, based on current estimates. Publicly available data indicate that 39 companies qualify as large firms according to SBA criteria. Many or all of the other 91 companies may qualify as small firms with fewer than 500 employees. We cannot determine the exact number because the criteria data are not readily available. However, because of the extremely high cost and technical complexity involved in exploration and development in deep water, the vast majority of lessees/operators affected by this rule will be large companies. Of the 211 leases in deep water with a discovery or production by mid-2000, 19 large firms are the lessee/operator of 193, while 7 small firms are lessee/operator of the other 18. While that ratio suggests a 1-in-12 chance that a small operator may apply for relief, 4 of the 8 past applications we received have been from small operators. This rule continues the same basic application system we now use. Small operators do not appear to be at a disadvantage in our application process.

Provisions of the rule, in comparison with existing rules for discretionary DWRR for pre-Act leases, may reduce applicant costs in three areas:

- First, new applications for DWRR will be based on a fully identified project rather than a whole, often incompletely identified, field. Consequently, applicants may need to provide less extensive geological and geophysical data. For instance, we will not require them to submit data on reservoirs that may be in the field but clearly are not part of the project. There is no sound basis for estimating the size of any savings associated with this reduced data burden because only some applications would involve potential extra reservoirs. For those that do, however, this change can reduce the amount of follow-up data we typically must request from applicants and can expedite our evaluation.
- Second, applicants may no longer have to incur the cost of additional drilling or acquisition of new seismic data to request a redetermination. While significant new geologic information or price or cost changes still enable a redetermination, applicants may now also seek a redetermination upon identification of a more efficient development system. That new reason could save drilling a new deep water well at a cost of $20 million or more, or acquiring additional seismic data at a cost of about $100,000 per tract. We have received no redetermination requests. We attribute this to the fact that the DWRR program has not been active long enough to reach the redetermination stage for most of the applications we have processed.
- Third, under this rule, we give successful applicants more time to initiate development than under existing rules. This added time gives operators more time to arrange financing and to negotiate contracts with suppliers. Again, there is no sound basis for estimating the size of any savings associated with this greater applicant flexibility. It is clear, however, that this change, too, cannot be considered to impose a significant adverse economic effect on a substantial number of small business entities. If anything, all three changes lessen the existing applicant cost burden.

Small Business Regulatory Enforcement Fairness Act (SBREFA)

This rule is not a major rule under 5 U.S.C. 804(2), the SBREFA. This rule: a. Does not have an annual effect on the economy of $100 million or more. This rule modifies some procedures used under the current rule, specifies how certain new deep water leases may qualify for royalty suspensions in the future, and describes circumstances not covered in the current regulations that may cause us to grant royalty relief. In general, the effect of qualifying for a royalty suspension increases production from a few marginal fields but does not change royalty collections—since without relief, no production or royalty payments would occur or be expected, so suspending them forfeits no revenue. To the extent that royalty relief encourages new production, it benefits applicants, one-half of which in the past have been small businesses. But only one of the five fields for which we have approved relief has gone into production.

b. Will not cause a major increase in costs or prices for consumers, individual industries, Federal, state, or local government agencies, or geographic regions. Oil prices are not based on the production from any one region, but are based on worldwide production and demand at any point in time. While natural gas prices are more localized, they correlate to oil prices. The rule does not change any existing leasing policies, so it should not cause prices to increase.

c. Does not have significant adverse effects on competition, employment, investment, innovation, or the ability of United States-based enterprises to compete with foreign-based enterprises. Leasing on the United States OCS is limited to citizens or residents of the United States, their associations, states, municipalities, or companies incorporated in the United States. This rule does not change that requirement, so it does not change the ability of United States firms to compete in any way.

Paperwork Reduction Act (PRA) of 1995

We examined the information collection requirements in the final rule and determined they remain unchanged from those currently approved by OMB under OMB control number 1010–0071, with a current expiration date of September 30, 2003. An 83–I submission to OMB is not required for review and approval under § 3507(d) of the PRA. The PRA 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.

The title of the collection of information is ''30 CFR part 203, Relief or Reduction in Royalty Rates.'' Respondents include approximately 130 Federal OCS oil and gas lessees. The frequency of response is on occasion. Responses to this collection of information are required to obtain or retain a benefit. MMS will protect proprietary information under applicable law and 30 CFR 203.63(b) and 250.196.

MMS uses the information to make decisions on the economic viability of leases requesting a suspension or elimination of royalty or net profit share. These decisions have substantial monetary impacts to both the lessee and the Federal Government. Royalty relief can lead to increased production of natural gas and oil, creating profits for lessees and tax revenues for the Government that they might not otherwise receive.

We estimate the total annual paperwork burden is 8,650 burden hours and $345,600 for the application and audit fee ''non-hour'' cost burdens authorized under § 203.3. The following chart provides a breakdown of the components of the estimated paperwork burden of part 203 final regulations.

Reporting or recordkeeping requirement 30 CFR Part 203	Application/audit fees		
	Annual responses	Hours per response	Annual burden hours
OCS Lands Act Reporting			
Application—leases that generate earnings that cannot sustain continued production (end-of-life lease)	2 applications	100 hours	200
	Application 2 × $12,000 = $24,000* Audit 1 × $10,000 = $10,000		
Application—apart from formal programs for royalty relief for marginal producing lease (expect less than 1 per year—new category).	1 Application	250 hours	250
	Application 1 × $15,000 = $15,000* Audit 1 × $10,000 = $10,000		
§ 203.55 Renounce relief arrangement (seldom, if ever will be used; minimal burden to prepare letter)	1 Letter	1 hour	1
§ 203.81, 203.83 through 203.89 required reports	Burden included with applications.		
OCS Lands Act Reporting Subtotal	4 responses	N/A	451
	Processing Fees = $59,000		
DWRAA Reporting			
Application—leases in designated areas of GOM deep water acquired in lease sale before 11/28/95 or after 11/28/00 and are producing (deep water expansion project).	1 Application	2,000 hours	2,000
	Application 1 × $39,000 = $39,000 Audit		
Application—leases in designated areas of deep water GOM, acquired in lease sale before 11/28/95 or after 11/28/00, that have not produced (pre-Act or post-2000 deep water leases).	1 Application	2,000 hours	2,000
	Application 1 × $49,000 = $49,000* Audit 1 × $25,000 = $25,000		
Application—short form to add or assign pre-Act lease	1 Application	40 hours	40
	Application 1 × $1,000 = $1,000 No Audit		
Application—preview assessment (seldom if ever will be used because applicants generally opt for binding determination by MMS instead).	1 Application	900 hours	900
	Application 1 × $46,600 = $46,600 No Audit		
Application—apart from formal programs for royalty relief for marginal expansion project or marginal non-producing lease (expect less than 1 per year—new category).	Application	1,000 hours	1,000
	Application 1 × $49,000 = $49,000 Audit 1 × $20,000 = $20,000		
Redetermination.	1 Redetermination	500 hours	500
	Application 1 × $32,000 = $32,000* Audit 1 × $25,000 = $25,000		
§ 203.70, 203.81, 203.90, 203.91 Submit fabricator's confirmation report	2 Reports	20 hours	40
§ 203.70, 203.81, 203.90, 203.92 2 Submit post-production development report	2 Reports*	50 hours	100
§ 203.77 Renounce relief arrangement (seldom, if ever will be used; minimal burden to prepare letter)	1 Letter	1 hour	1

Reporting or recordkeeping requirement 30 CFR Part 203	Application/audit fees		
	Annual responses	Hours per response	Annual burden hours
§ 203.79(a) Request reconsideration of MMS field designation	4 Requests	400 hours	1,600
§ 203.79(c) Request extension of deadline to start construction	1 Request	2 hours	2
§ 203.81, 203.83 through 230.89 Required reports	Burden included with applications		0
DWRR Act Reporting Subtotal	16 Responses	N/A	8,183
	Processing Fees = $286,600		
Recordkeeping Burden			
§ 203.91 Retain supporting cost records for post-production development/fabrication reports (records retained as usual/customary business practice; minimal burden to make available at MMS request).	2 Record-keepers	8 hours	16

• In addition, under § 203.81, a report prepared by an independent CPA must accompany the application and post-production report (except expansion project, short form, and preview assessment applications are excluded). The OCS Lands Act applications will require this report only once; the DWRR Act applications will require this report at two stages—with the application and with the post-production development report for successful applicants. We estimate an average cost for a report is $45,000, and that seven CPA certifications per year will be necessary if the applications are approved. The total estimated annual ''non-hour'' cost burden for this requirement is $315,000 ($45,000 per certification × 7 CPA certifications = $315,000).

Federalism (Executive Order 13132)

Under Executive Order 13132, this rule does not have Federalism implications. The rule neither substantially nor directly affects the relationship between the Federal and State Governments. This rule affects the collection of royalty revenues from deepwater lessees in the GOM, all of which is outside State jurisdiction. States have no role in this activity with or without this rule. This rule does not impose costs on States or localities. States and local governments play no part in the administration of the DWRR program.

Takings Implications Assessment (Executive Order 12630)

Under Executive Order 12630, the rule does not have significant Takings implications. A Takings Implication Assessment is not required because the rule would not take away or restrict a bidder's right to acquire or develop OCS leases.

Energy Supply, Distribution, or Use (Executive Order 13211)

This rule is a significant rule and is subject to review by the Office of Management and Budget under Executive Order 12866. The rule does not have a significant effect on energy supply, distribution, or use because its promotes, rather than adversely affects, the production of additional oil and gas from the OCS. It promotes energy supply from marginal domestic sources by broadening applicability of the process by which we may lower costs for those producers.

Unfunded Mandates Reform Act (UMRA)

This rule does not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than $100 million per year. The rule does not have a significant or unique effect on State, local, or tribal governments. The rule modifies some procedures in the existing regulation, describes how certain new leases may qualify for royalty suspensions, and specifies circumstances that might cause us to grant royalty relief outside our formal programs. None of these changes involve state, local, or tribal mandates. A statement containing additional UMRA (2 U.S.C. 1531 *et seq.*) information is not required.

Civil Justice Reform (Executive Order 12988)

Under Executive Order 12988, the Office of the Solicitor has determined that this rule does not unduly burden the judicial system and meets the requirements of sections 3(a) and 3(b)(2) of the Order.

National Environmental Policy Act (NEPA) of 1969

This rule does not constitute a major Federal action significantly affecting the quality of the human environment. A detailed statement under the NEPA is not required.

Government-to-Government Relationship With Tribes

Pursuant to the President's memorandum of April 29, 1994, ''Government-to-Government Relations with Native American Tribal Governments'' (59 FR 22951) and 512 DM 2, we have determined that there are no effects from this action on federally recognized Indian tribes.

List of Subjects in 30 CFR Part 203

Continental shelf, Government contracts, Indians-lands, Minerals royalties, Oil and gas exploration, Public lands-mineral resources, Reporting and recordkeeping requirements, Sulphur.

Dated: December 18, 2001.

James E. Cason,

Acting Deputy Secretary.

For the reasons stated in the preamble, the Minerals Management Service (MMS) amends 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 *et seq.*; 43 U.S.C. 1301 *et seq.*; 43 U.S.C. 1331 *et seq.*; and 43 U.S.C. 1801 *et seq.*

2. Section 203.0 is amended by removing the definition of ''Sunk costs,'' adding definitions for ''Development project,'' ''Royalty suspension (RS) lease,'' ''Sunk costs for an authorized field,'' and ''Sunk costs for an expansion or development project'' in alphabetical order, and revising the definitions for ''Authorized field,'' ''Eligible lease,'' ''Expansion project,'' ''Fabrication (or start of construction),'' ''New production,'' ''Pre-Act lease,'' and ''Redetermination,'' to read as follows:

§ 203.0 What definitions apply to this part?

Authorized field means a field:

(1) Located in a water depth of at least 200 meters and in the Gulf of Mexico (GOM) west of 87 degrees, 30 minutes West longitude;

(2) That includes one or more pre-Act leases; and

(3) From which no current pre-Act lease produced, other than test production, before November 28, 1995;

* * * * *

Development project means a project to develop one or more oil or gas reservoirs located on one or more contiguous leases that:

(1) Were issued in a sale held after November 28, 2000;

(2) Are located in a water depth of at least 200 meters and in the GOM wholly west of 87 degrees, 30 minutes West longitude; and

(3) Have had no production (other than test production) before the current application for royalty relief.

* * * * *

Eligible lease means a lease that:

(1) Is issued as part of an OCS lease sale held after November 28, 1995, and before November 28, 2000;

(2) Is located in the Gulf of Mexico in water depths of 200 meters or deeper;

(3) Lies wholly west of 87 degrees, 30 minutes West longitude; and

(4) Is offered subject to a royalty suspension volume.

Expansion project means a project you propose in a Development Operations Coordination Document (DOCD) or a Supplement approved by the Secretary of the Interior after November 28, 1995, that will significantly increase the ultimate recovery of resources from one or more reservoirs that have not produced on a pre-Act lease or a lease issued in a sale held after November 28, 2000. A significant increase does not simply extend recovery from reservoirs already in production. For a pre-Act lease, the expansion project must also involve a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well project, etc.). For a lease issued after November 28, 2000, the expansion project must involve a new well drilled into a reservoir that has not previously produced. In all cases, all leases in an expansion project must be wholly located in a water depth of at least 200 meters and in the GOM wholly west of 87 degrees, 30 minutes West longitude.

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

* * * * *

New production means any production from a current pre-Act lease from which no royalties are due on production, other than test production, before November 28, 1995. Also, it means any additional production resulting from new lease-development activities on a lease issued in a sale after November 28, 2000, or a current pre-Act lease under a DOCD or a Supplement approved by the Secretary of the Interior after November, 28, 1995.

* * * * *

Pre-Act lease means a lease that:

(1) Results from a sale held before November 28, 1995;

(2) Is located in the GOM in water depths of 200 meters or deeper; and

(3) Lies wholly west of 87 degrees, 30 minutes West longitude.

* * * * *

Redetermination means our reconsideration of our determination on royalty relief because you request it after:

(1) We have rejected your application;

(2) We have granted relief but you want a larger suspension volume;

(3) We withdraw approval; or

(4) You renounce royalty relief.

* * * * *

Royalty suspension (RS) lease means a lease that:

(1) Is issued as part of an OCS lease sale held after November 28, 2000;

(2) Is in locations or planning areas specified in a particular Notice of OCS Lease Sale offering that lease; and

(3) Is offered subject to a royalty suspension specified in a Notice of OCS Lease Sale published in the **Federal Register**.

Sunk costs for an authorized field means the after-tax eligible costs that you (not third parties) incur for exploration, development, and production from the spud date of the first discovery on the field to the date we receive your complete application for royalty relief. The discovery well must be qualified as producible under part 250, subpart A of this title. Sunk costs include the rig mobilization and material costs for the discovery well that you incurred before its spud date.

Sunk costs for an expansion or development project means the after-tax eligible costs that you (not third parties) incur for only the first well that encounters hydrocarbons in the reservoir(s) included in the application and that meets the producibility requirements under part 250, subpart A of this chapter on each lease participating in the application. Sunk costs include rig mobilization and material costs for the discovery wells that you incurred before their spud dates.

* * * * *

3. Section 203.2 is revised to read as follows:

§ 203.2 How can I get royalty relief?

We may reduce or suspend royalties for Outer Continental Shelf (OCS) leases or projects that meet the criteria in the following table.

If you have a lease . . .	And if you . . .	Then we may grant you . . .
(a) With earnings that cannot sustain production (i.e., *End-of-life lease*).	Would abandon otherwise potentially recoverable resources but seek to increase production by operating beyond the point at which the lease is economic under the existing royalty rate.	A reduced royalty rate on current monthly production and a higher royalty rate on additional monthly production. (See §§ 203.50 through 203.56.)

If you have a lease . . .	And if you . . .	Then we may grant you . . .
(b) Located in a designated GOM deep water area, and acquired in a lease sale before November 28, 1995, or after November 28, 2000, and you propose in a DOCD or supplement to expand production significantly.	Are producing and seek to increase ultimate resource recovery from one or more reservoirs not previously or currently producing on the field or lease, not simply extend recovery of reservoirs that already produced. (*Expansion project*).	A royalty suspension for additional production large enough to make the project economic. (See §§ 203.60 through 203.79.)
(c) Located in a designated GOM deep water area and acquired in a lease sale held before November 28, 1995 (*Pre-Act lease*).	Are on a field from which no current pre-Act lease produced (other than test production) before November 28, 1995 (*Authorized field)*.	A royalty suspension for a minimum production volume plus any additional volume needed to make the field economic. (See §§ 203.60 through 203.79.)
(d) Located in a designated GOM deep water area and acquired in a lease sale held after November 28, 2000.	Have not produced and can demonstrate that the suspension volume, if any, in your lease is not enough to make development economic (*Development project*).	A royalty suspension for a minimum production volume plus any additional volume needed to make your project economic. (See §§ 203.60 through 203.79.)
(e) Where royalty relief would recover significant additional resources or, in certain areas of the GOM, would enable development.	Are not eligible to apply for end-of-life or deep water royalty relief, but show us you meet certain elligibility conditions.	A royalty modification in size, duration, or form that makes your lease or project economic. (See § 203.80.)

4. Section 203.4 is revised to read as follows:

§ 203.4 How do the provisions in this part apply to different types of leases and projects?

The tables in this section summarize how similar provisions of this part apply in different situations.

(a) We require the information elements indicated by an X in the following table and described in §§ 203.51, 203.62, and 203.81 through 203.89 for applications for royalty relief.

Information elements	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) Administrative information report	X	X	X	X
(2) Net revenue and relief justification report (prescribed format)	X			
(3) Economic viability and relief justification report (Royalty Suspension Viability Program (RSVP) model inputs justified with Geological and Geophysical (G&G), Engineering, Production, & Cost reports)		X	X	X
(4) G&G report		X	X	X
(5) Engineering report		X	X	X
(6) Production report		X	X	X
(7) Deep water cost report		X	X	X

(b) We require the confirmation elements indicated by an X in the following table and described in §§ 203.70, 203.81 and 203.90 through 203.91 to retain royalty relief.

Confirmation elements	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) Fabricator's confirmation report		X	X	X
(2) Post-production development report approved by an independent certified public accountant (CPA)		X	X	X

(c) The following table indicates by an X, and §§ 203.50, 203.52, 203.60 and 203.67 describe, the prerequisites for our approval of your royalty relief application.

Approval conditions	End-of-life lease	Deep water		
		Expansion	Pre-act lease	Development project
(1) At least 12 of the last 15 months have the required level of production	X			
(2) Already producing	X			
(3)A producible well into a reservoir that has not produced before		X	X	X
(4) Royalties for qualifying months exceed 75% of net revenue (NR)	X			
(5) Substantial investment on a pre-Act lease (e.g., platform, subsea template)		X		

Approval conditions	End-of-life lease	Deep water		
		Expansion	Pre-act lease	Development project
(6) Determined to be economic only with relief		X	X	X

(d) The following table indicates by an X, and §§ 203.52 and 203.74 through 203.75 describe, the prerequisites for a redetermination of our royalty relief decision.

Redetermination conditions	End-of-Life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) After 12 months under current rate, criteria same as for approval	X			
(2) For material change in geologic data, prices, costs, or available technology		X	X	X

(e) The following table indicates by an X, and §§ 203.53 and 203.69 describe, the characteristics of approved royalty relief.

Relief rate and volume, subject to certain conditions	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) One-half pre-application effective lease rate on the qualifying amount, 1.5 times pre-application effective lease rate on additional production up to twice the qualifying amount, and the pre-application effective lease rate for any larger volumes	X			
(2) Qualifying amount is the average monthly production for 12 qualifying months	X			
(3) Zero royalty rate on the suspension volume and the original lease rate on additional production		X	X	X
(4) Suspension volume is at least 17.5, 52.5 or 87.5 million barrels of oil equivalent (MMBOE)			X	
(5) Suspension volume is at least the minimum set in the Notice of Sale, the lease, or the regulations		X		X
(6) Amount needed to become economic		X	X	X

(f) The following table indicates by an X, and §§ 203.54 and 203.78 describe, circumstances under which we discontinue your royalty relief.

Full royalty resumes when	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) Average NYMEX price for last 12 months is at least 25 percent above the average for the qualifying months	X			
(2) Average NYMEX price for last calendar year exceeds $28/bbl or $3.50/mcf, escalated by the gross domestic product (GDP) deflator since 1994		X	X	
(3) Average prices for designated periods exceed levels we specify in the Notice of Sale or the lease		X		X

(g) The following table indicates by an X, and §§ 203.55 and 203.76 through 203.77 describe, circumstances under which we end or reduce royalty relief.

Relief withdrawn or reduced	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) If recipient requests	X	X	X	X
(2) Lease royalty rate is at the effective rate for 12 consecutive months	X			
(3) Conditions occur that we specified in the approval letter in individual cases	X			
(4) Recipient does not submit post-production report that compares expected to actual costs		X	X	X

Relief withdrawn or reduced	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(5) Recipient changes development system		X	X	X
(6) Recipient excessively delays starting fabrication		X	X	X
(7) Recipient spends less than 80 percent of proposed pre-production costs prior to start of production		X	X	X
(8) Amount of relief volume is produced		X	X	X

5. Section 203.60 is revised to read as follows:

§ 203.60 Who may apply for deep water royalty relief?

You may apply for royalty relief under §§ 203.61(b) and 203.62 if:

(a) You are a lessee of a lease in water at least 200 meters deep in the GOM and lying wholly west of 87 degrees, 30 minutes West longitude;

(b) We have assigned your pre-Act lease to a field (as defined in § 203.0); and

(c) You either:

(1) Hold a pre-Act lease on an authorized field (as defined in § 203.0) or

(2) Propose an expansion project (as defined in § 203.0) or

(3) Propose a development project (as defined in § 203.0).

6. In § 203.62, the introductory sentence and paragraph (c) are revised to read as follows:

§ 203.62 How do I apply for relief?

You must send a complete application and the required fee to the MMS Regional Director for the GOM.

* * * * *

(c) Sections 203.81, 203.83, and 203.85 through 203.89 describe what these reports must include. The MMS regional office for the GOM will guide you on the format for the required reports, and we encourage you to contact this office prior to preparing your application for this guidance.

7. In § 203.63, the following changes are made:

A. Paragraphs (a), (b), and (c) following the introductory paragraph are redesignated paragraphs (a)(1), (a)(2), and (a)(3).

B. The introductory paragraph is redesignated (a) and is revised to read as set forth below.

C. A new paragraph (b) is added as set forth below.

§ 203.63 Does my application have to include all leases in the field?

(a) For authorized fields, we will accept only one joint application for all leases that are part of the designated field on the date of application, except as provided in paragraph (a)(3) of this section and § 203.64. However, we will evaluate all acreage that may eventually become part of the authorized field. Therefore, if you have any other leases that you believe may eventually be part of the authorized field, you must submit data for these leases according to § 203.81.

* * * * *

(b) If your application seeks only relief for a development project or an expansion project, your application does not have to include all leases in the field.

8. In § 203.64, the section heading and the first sentence in the introductory paragraph are revised to read as follows:

§ 203.64 How many applications may I file on a field or a development project?

You may file one complete application for royalty relief during the life of the field or for a development project or an expansion project designed to produce a reservoir or set of reservoirs. * * *

* * * * *

9. In § 203.65, paragraph (b) is revised to read as follows:

§ 203.65 How long will MMS take to evaluate my application?

* * * * *

(b) We will evaluate your first application on a field within 180 days, evaluate your first application on a development project or an expansion project within 150 days and evaluate a redetermination under § 203.75 within 120 days after we determine that it is complete.

* * * * *

10. Section 203.66 revised to read as follows:

§ 203.66 What happens if MMS does not act in the time allowed?

If we do not act within the timeframes established under § 203.65, you get royalty relief according to the following table.

If you apply for royalty relief for	And we do not decide within the time specified	As long as you
(a) An authorized field	You get the minimum suspension volumes specified in § 203.69.	Abide by §§ 203.70 and 203.76.
(b) An expansion project	You get a royalty suspension for the first year of production.	Abide by §§ 203.70 and 203.76.
(c) A development project	You get a royalty suspension for initial production for the number of months that a decision is delayed beyond the stipulated timeframes set by § 203.65, plus all the royalty suspension volume for which you qualify.	Abide by §§ 203.70 and 203.76.

11. Section 203.67 is revised to read as follows:

§ 203.67 What economic criteria must I meet to get royalty relief on an authorized field or project?

We will not approve applications if we determine that royalty relief cannot make the field, development project, or expansion project economically viable. Your field or project must be uneconomic while you are paying royalties and must become economic with royalty relief.

12. In § 203.68, paragraph (b) is revised to read as follows:

§ 203.68 What pre-application costs will MMS consider in determining economic viability?

* * * * *

(b) We will consider sunk costs according to the following table.

We will	When determining
(1) Include sunk costs	Whether a field that includes a pre-Act lease which has not produced, other than test production, before the application or redetermination submission date needs relief to become economic.
(2) Not include sunk costs	Whether an authorized field, a development project, or an expansion project can become economic with full relief (see § 203.67).
(3) Not include sunk costs	How much suspension volume is necessary to make the field, a development project, or an expansion project economic (see § 203.69(c)).
(4) Include sunk costs for the project discovery well on each lease.	Whether a development project or an expansion project needs relief to become economic.

13. In § 203.69, the introductory paragraph and paragraphs (b) through (e) are revised, and paragraph (f) is added to read as follows:

§ 203.69 If my application is approved, what royalty relief will I receive?

If we approve your application, subject to certain conditions, we will not collect royalties on a specified suspension volume for your field, development project, or expansion project. Suspension volumes include volumes allocated to a lease under an approved unit agreement, but exclude any volumes of production that are not normally royalty-bearing under the lease or the regulations of this chapter (e.g., fuel gas).

* * * * *

(b) For development projects, any relief we grant applies only to project wells and replaces the royalty suspension volume with which we issued your lease. If your project is economic given the royalty suspension volume with which we issued your lease, we will reject the application. Otherwise, the *minimum* royalty suspension volumes are as shown in the following table:

For	The minimum royalty suspension volume is	Plus
(1) RS leases	A volume equal to the combined royalty suspension volumes (or the volume equivalent based on the data in your approved application for other forms of royalty suspension) with which we issued the leases participating in the application that have or plan a well into a reservoir identified in the application.	10 percent of the median of the distribution of known recoverable resources upon which we based approval of your application from all reservoirs included in the project.
(2) Other deep water leases issued in sales after November 28, 2000.	A volume equal to 10 percent of the median of the distribution of known recoverable resources upon which we based approval of your application from all reservoirs included in the project.	

(c) If your application includes pre-Act or eligible leases in different categories of water depth, we apply the minimum royalty suspension volume for the deepest such lease then assigned to the field. We base the water depth and makeup of a field on the water-depth delineations in the ''Lease Terms and Economic Conditions'' map and the ''Field Names Master List'' documents and updates in effect at the time your application is deemed complete. These publications are available from the MMS Regional Office for the GOM.

(d) You will get a royalty suspension volume above the minimum if we determine that you need more to make the field or development project economic.

(e) For expansion projects, the minimum royalty suspension volume equals 10 percent of the median of the distribution of known recoverable resources upon which we based approval of your application from all reservoirs included in your project plus any suspension volumes required under § 203.66. If we determine that your expansion project may be economic only with more relief, we will determine and grant you the royalty suspension volume necessary to make the project economic.

(f) The royalty suspension volume applicable to specific leases will continue through the end of the month in which cumulative production reaches that volume. You must calculate cumulative production from all the leases in the authorized field or project that are entitled to share the royalty suspension volume.

14. Section 203.70 is revised to read as follows:

§ 203.70 What information must I provide after MMS approves relief?

You must submit reports to us as indicated in the following table. Sections 203.81, 203.90, and 203.91 describe what these reports must include. The MMS regional office for the GOM will prescribe the formats.

Required report	When due to MMS	Due date extensions
(a) Fabricator's confirmation report	Within 18 months after approval of relief	MMS Director may grant you an extension under § 203.79(c) for up to 6 months.
(b) Post-production report	Within 120 days after the start of production that is subject to the approved royalty suspension volume.	With acceptable justification from you, MMS Regional Director for the GOM may extend due date up to 30 days.

15. In § 203.71, the introductory paragraph and paragraphs (a) through (c) are revised to read as follows:

§ 203.71 How does MMS allocate a field's suspension volume between my lease and other leases on my field?

The allocation depends on when production occurs, when we issued the lease, when we assigned it to the field, and whether we award the volume suspension by an approved application or establish it in the lease terms, as prescribed in this section.

(a) If your authorized field has an approved royalty suspension volume under §§ 203.67 and 203.69, we will suspend payment of royalties on production from all leases in the field that participate in the application until their cumulative production equals the approved volume. The following conditions also apply:

If . . .	Then . . .	And . . .
(1) We assign an eligible lease to your field after we approve relief.	We will not change your field's royalty suspension volume.	The assigned lease(s) may share in any remaining royalty relief.
(2) We assign a pre-Act or post-November 2000 deep water lease to your field after we approve your application.	We will not change your field's royalty suspension volume.	The assigned lease(s) may share in any remaining royalty relief by filing the short-form application specified in § 203.83 and authorized in § 203.82. An assigned RS lease also gets any portion of its royalty suspension volume remaining even after the field has produced the approved relief volume.
(3) We assign another lease(s) that you operate to your field while we are evaluating your application.	We will change your field's minimum suspension volume if the assigned lease is a pre-Act or eligible lease entitled to a larger minimum or automatic suspension volume.	(i) You toll the time period for evaluation until you modify your application to be consistent with the new field; (ii) We have an additional 60 days to review the new information; and (iii) The assigned lease(s) shares the royalty suspension we grant to the new field. If you do not agree to toll, we will have to reject your application due to incomplete information. But, an eligible lease we assigned to the field kept its automatic suspension volume.
(4) We assign another operator's lease to your field while we are evaluating your application.	We will change your field's minimum suspension volume provided the assigned lease joins the application and is entitled to a larger minimum suspension volume.	(i) You both toll the time period for evaluation until both of you modify your application to be consistent with the new field; (ii) We have an additional 60 days to review the new information; and (iii) The assigned lease(s) shares the royalty suspension we grant to the new field. If you (the original applicant) do not agree to toll, the other operator's lease retains any suspension volume it has or may share in any relief that we grant by filing the short form application specified in § 203.83 and authorized in § 203.82.
(5) We reassign a well on a pre-Act, eligible, or post-November 2000 deep water lease to another field.	The past production from the well counts toward the royalty suspension volume of the field to which we assigned the well.	The past production from that well will not count toward any royalty suspension volume granted to the field from which we reassigned it.

(b) If your authorized field has a royalty suspension volume established under § 260.111 of this title (i.e., a field with a pre-Act lease where an eligible lease starts production first), we will suspend payment of royalties on production from all eligible leases in the field until their cumulative production equals the established volume. The following conditions also apply:

If . . .	Then . . .	And . . .
(1) We assign another eligible lease to your field.	Your field's royalty suspension volume does not change.	The assigned lease may share in any remaining royalty relief.
(2) We assign an RS lease to your field	Your field's royalty suspension volume does not change.	The assigned lease gets only the volume suspension with which we issued it, and its production volume counts against the field's royalty suspension volume.
(3) We assign a pre-Act lease or a lease issued after November 2000 without royalty suspension to your field.	Your field's royalty suspension volume does not change.	We assign lease shares none of the volume suspension, and its production does not count as part of the suspension volume.
(4) A pre-Act or post-November 2000 deep water lease applies (along with the other leases in the field) and qualifies (subject to any pre-existing suspension volumes) for royalty relief under §§ 203.67 and 203.69.	Your field's royalty suspension volume may increase or stay the same, but will not diminish.	(i) All leases in the field share the royalty suspension volume if we approve the application; or (ii) The eligible or RS leases in the field keep their respective volumes if we reject the application.

(c) When a project has more than one lease, the royalty suspension volume for each lease equals that lease's actual production from the project (or production allocated under an approved unit agreement) until total production for all leases in the project equals the project's approved royalty suspension volume.

* * * * *

16. In § 203.74, the introductory paragraph is revised, paragraphs (b) and (c) are redesignated as paragraphs (c) and (d) and revised, and a new paragraph (b) is added to read as follows:

§ 203.74 When will MMS reconsider its determination?

You may request a redetermination after we withdraw approval or after you renounce royalty relief, unless we withdraw approval due to your providing false or intentionally inaccurate information. Under certain conditions you may also request a redetermination if we deny your application or if you want your approved royalty suspension volume to change. In these instances, to be eligible for a redetermination, at least one of the following four conditions must occur.

* * * * *

(b) You demonstrate in your new application that the technology that most efficiently develops this field or lease was not considered or deemed feasible in the original application. Your newly proposed technology must improve the profitability, under equivalent market conditions, of the field or lease relative to the development system proposed in the prior application.

(c) Your current reference price decreases by more than 25 percent from your base reference price as calculated under this paragraph.

(1) Your current reference price is a weighted-average of daily closing prices on the NYMEX for light sweet crude oil and natural gas over the most recent full 12 calendar months;

(2) Your base reference price is a weighted average of daily closing prices on the NYMEX for light sweet crude oil and natural gas for the full 12 calendar months preceding the date of your most recently approved application for this royalty relief; and

(3) The weighting factors are the proportions of the total production volume (in BOE) for oil and gas associated with the most likely scenario (identified in §§ 203.85 and 203.88) from your most recently approved application for this royalty relief.

(d) Before starting to build your development and production system, you have revised your estimated development costs, and they are more than 120 percent of the eligible development costs associated with the most likely scenario from your most recently approved application for this royalty relief.

17. In § 203.76, paragraphs (a), (b), and (c) are revised to read as follows:

§ 203.76 When might MMS withdraw or reduce the approved size of my relief?

* * * * *

(a) You change the type of development system proposed in your application (e.g., change from a fixed platform to floating production system, or from an independent development and production system to one with subsea wells tied back to a host production facility, etc.).

(b) You do not start building the proposed development and production system within18 months of the date we approved your application, unless the MMS Director grants you an extension under § 203.79(c). If you start building the proposed system and then suspend its construction before completion, and you do not restart continuous building of the proposed system within 18 months of our approval, we will withdraw the relief we granted.

(c) Your actual development costs are less than 80 percent of the eligible development costs estimated in your application's most likely scenario, and you do not report that fact in your post-production development report (§ 203.70). Development costs are those expenditures defined in § 203.89(b) incurred between the application submission date and start of production. If you report this fact in the post-production development report, you may retain the lesser of 50 percent of the original royalty suspension volume or 50 percent of the median of the distribution of the potentially recoverable resources anticipated in your application.

* * * * *

18. Section 203.77 is revised to read as follows:

§ 203.77 May I voluntarily give up relief if conditions change?

Yes, by sending a letter to that effect to the MMS Regional Director for the GOM.

19. In § 203.78, the introductory paragraph, and paragraphs (a)(1), (b)(1) and (f) are revised to read as follows:

§ 203.78 Do I keep relief if prices rise significantly?

If prices rise above a base price for light sweet crude oil or natural gas, set by statute for pre-Act leases, indicated in your original lease agreement or Notice of Sale for post-November 2000 deep water leases, you must pay full royalties as prescribed in this section. For post-November 2000 deepwater leases, price thresholds apply on a lease basis, so different leases on the same field, development project, or expansion project may have different price thresholds.

(a) * * *

(1) Pay royalties on all oil production for the previous year at the lease stipulated royalty rate plus interest (under 30 U.S.C. 1721 and § 218.54 of this chapter) by March 31 of the current calendar year, and

* * * * *

(b) * * *

(1) Pay royalties on all natural gas production for the previous year at the lease stipulated royalty rate plus interest (under 30 U.S.C. 1721 and § 218.54 of this chapter) by March 31 of the current calendar year, and

* * * * *

(f) We change the prices referred to in paragraphs (a), (b), and (d) of this section periodically. For pre-Act leases, these prices change during each calendar year after 1994 by the percentage that the implicit price deflator for the gross domestic product changed during the preceding calendar year. For post-November 2000 deepwater leases, these prices change as indicated in the lease instrument or in the Notice of Sale under which we issued the lease.

20. Section 203.80 is added to read as follows:

§ 203.80 When can I get royalty relief if I am not eligible for end-of-life or deep water royalty relief?

We may grant royalty relief when it serves the statutory purposes summarized in § 203.1, and our formal relief programs provide inadequate encouragement to increase production or development. Unless your lease lies wholly west of 87 degrees, 30 minutes West longitude in the Gulf of Mexico, your lease must be producing to qualify for relief. Before you may apply for royalty relief apart from our end-of-life or deepwater programs, we must agree that your lease or project has two or more of the following characteristics:

(a) The lease has produced for a substantial period and the lessee can recover significant additional resources. Significant additional resources means enough to allow production for at least a year more than would be profitable without royalty relief.

(b) Valuable facilities (e.g., a platform or pipeline that would be removed upon lease relinquishment) exist that we do not expect a successor lessee to use. If the facilities are located off the lease, their preservation must depend on continued production from the lease applying for royalty relief. We will only consider an allocable share of costs for off-lease facilities in the relief application.

(c) A substantial risk exists that no new lessee will recover the resources.

(d) The lessee made major efforts to reduce operating costs too recently to use the formal program for royalty relief (e.g., recent significant change in operations).

(e) Circumstances beyond the lessee's control, other than water depth, preclude reliance on one of the existing royalty relief programs.

21. In § 203.81, paragraphs (a) and (c) are revised to read as follows:

§ 203.81 What supplemental reports do royalty relief applications require?

(a) You must send us the supplemental reports, indicated in the following table by an X, that apply to your field. Sections 203.83 through 203.91 describe these reports in detail.

Required reports	End-of-life lease	Deep water: Expansion project	Deep water: Pre-act lease	Deep water: Development project
(1) Administrative information Report	X	X	X	X
(2) Net revenue & relief justification report	X			
(3) Economic viability & relief justification report (RSVP model imputs justified by other required reports).		X	X	X
(4) G&G report.		X	X	X
(5) Engineering report.		X	X	X
(6) Production report.		X	X	X
(7) Deep water cost report		X	X	X
(8) Fabricator's confirmation report.		X	X	X
(9) Post-production development report.		X	X	X

* * * * *

(c) With your application and post-production development report, you must submit an additional report prepared by an independent CPA that:

(1) Assesses the accuracy of the historical financial information in your report; and

(2) Certifies that the content and presentation of the financial data and information conform to our most recent guidelines on royalty relief. This means the data and information must—

(i) Include only eligible costs that are incurred during the qualification months; and

(ii) Be shown in the proper format.

* * * * *

22. In § 203.83, paragraph (c) is revised to read as follows:

§ 203.83 What is in an administrative information report?

* * * * *

(c) Well number, API number, location, and status of each well that has been drilled on the field or lease or project (not required for non-oil and gas leases);

* * * * *

23. In § 203.86, the following changes are made:

A. The word ''and'' is removed at the end of paragraph (b)(6).

B. The ''.'' is removed and ''; and'' is added at the end of paragraph (b)(7).

C. Paragraph (b)(8) is added.

D. Paragraph (c)(4) is revised.

E. The word ''and'' is removed at the end of paragraph (d)(6).

F. The ''.'' is removed and ''; and'' is added at the end of paragraph (d)(7)

G. Paragraph (d)(8) is added.

The revisions and additions read as follows:

§ 203.86 What is in a G&G report?

* * * * *

(b) * * *

(8) A table listing the wells and completions, and indicating which sands and fault blocks will be targeted for completion or recompletion.

(c) * * *

(4) An explanation for excluding the reservoirs you are not planning to develop.

(d) * * *

(8) Reserve or resource distribution by reservoir.

* * * * *

24. In § 203.87, paragraphs (a)(1) and (d) are revised to read as follows:

§ 203.87 What is in an engineering report?

* * * * *

(a) * * *

(1) Its size along with basic design specifications and drawings; and

* * * * *

(d) A discussion of any plans for multi-phase development which includes the conceptual basis for developing in phases and goals or milestones required for starting later phases.

* * * * *

25. In § 203.89, paragraph (a) is revised to read as follows:

§ 203.89 What is in a deep water cost report?

* * * * *

(a) Sunk costs. Report sunk costs in dollars not adjusted for inflation and only if you have documentation.

* * * * *

26. In § 203.91, a new last sentence is added to read as follows:

§ 203.91 What is in a post-production development report?

* * * Also, you must have this report certified by an independent CPA according to § 203.81(c).

[FR Doc. 02–438 Filed 1–14–02; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[OPP–301199; FRL–6816–4]

RIN 2070–AB78

Fenbuconazole; Pesticide Tolerance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation extends time-limited tolerances for the combined residues of the fungicide fenbuconazole [*alpha*-(2-(4-chlorophenyl)-ethyl)-*alpha*-phenyl-3-(1*H*-1,2,4-triazole)-1-propanenitrile] and its metabolites, *cis* and *trans*-5-(4-chlorophenyl)-dihydro-3-phenyl-3-(1*H*-1,2,4-triazole-1-ylmethyl)-2-3*H*-furanone], expressed as fenbuconazole, in or on the stone fruit (except plums and prunes) crop group at 2.0 parts per million (ppm), pecans at 0.1 ppm, and bananas at 0.3 ppm until December 31, 2004, at which time they will expire and be revoked. Dow AgroSciences LLC (then Rohm and Haas Company) requested that these temporary tolerances be made permanent under the provisions of the Federal Food, Drug, and Cosmetic Act, as amended by the Food Quality Protection Act of 1996.

DATES: This regulation is effective January 15, 2002. Objections and requests for hearings, identified by docket control number OPP–301199, must be received by EPA on or before March 18, 2002.

ADDRESSES: Written objections and hearing requests may be submitted by mail, in person, or by courier. Please follow the detailed instructions for each method as provided in Unit VI. of the **SUPPLEMENTARY INFORMATION**. To ensure proper receipt by EPA, your objections and hearing requests must identify docket control number OPP–301199 in the subject line on the first page of your response.

FOR FURTHER INFORMATION CONTACT: By mail: Cynthia Giles-Parker, Product Manager 22, Registration Division (7505C), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone number: (703) 305–7740; and e-mail address: giles-parker.cynthia@epa.gov.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

You may be affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. Potentially affected categories and entities may include, but are not limited to:

Categories	NAICS codes	Examples of potentially affected entities
Industry	111	Crop production
	112	Animal production
	311	Food manufacturing
	32532	Pesticide manufacturing

This listing is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in the table could also be affected. The North American Industrial Classification System (NAICS) codes have been provided to assist you and others in determining whether or not this action might apply to certain entities. If you have questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT**.

B. How Can I Get Additional Information, Including Copies of this Document and Other Related Documents?

1. *Electronically*.You may obtain electronic copies of this document, and certain other related documents that might be available electronically, from the EPA Internet Home Page at http://www.epa.gov/. To access this document, on the Home Page select ‘‘Laws and Regulations,’’ ‘‘Regulations and Proposed Rules,’’ and then look up the entry for this document under the ‘‘**Federal Register**—Environmental Documents.’’ You can also go directly to the**Federal Register** listings at http://www.epa.gov/fedrgstr/. A frequently updated electronic version of 40 CFR part 180 is available at http://www.access.gpo.gov/nara/cfr/cfrhtml_00/Title_40/40cfr180_00.html, a beta site currently under development.

2. *In person*. The Agency has established an official record for this action under docket control number OPP–301199. The official record consists of the documents specifically referenced in this action, and other information related to this action, including any information claimed as Confidential Business Information (CBI). This official record includes the documents that are physically located in the docket, as well as the documents that are referenced in those documents. The public version of the official record does not include any information claimed as CBI. The public version of the official record, which includes printed, paper versions of any electronic comments submitted during an applicable comment period is available for inspection in the Public Information and Records Integrity Branch (PIRIB), Rm. 119, Crystal Mall #2, 1921 Jefferson Davis Hwy., Arlington, VA, from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The PIRIB telephone number is (703) 305–5805.

II. Background and Statutory Findings

In the **Federal Register** of March 23, 2001 (66 FR 16226) (FRL–6767–3), EPA issued a notice pursuant to section 408 of the Federal Food, Drug, and Cosmetic Act (FFDCA), 21 U.S.C. 346a, as amended by the Food Quality Protection Act of 1996 (FQPA) (Public Law 104–170), announcing the filing of pesticide petitions (PP 1F3989, 1F3995, and 2F4154) to make temporary tolerances permanent by Dow AgroSciences LLC,