30A1499, and a total of 484 engines in the worldwide fleet. The total cost to the domestic fleet to remove and replace these disks at the new life limit of 4000 CIS, rather than the former life limit of 5000 CIS, is estimated to be $6,331,015.

Regulatory Impact

This proposed rule does not have federalism implications, as defined in Executive Order 13132, because it would not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Accordingly, the FAA has not consulted with state authorities prior to publication of this proposed rule.

For the reasons discussed above, I certify that this proposed regulation (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) if promulgated, will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A copy of the draft regulatory evaluation prepared for this action is contained in the Rules Docket. A copy of it may be obtained by contacting the Rules Docket at the location provided under the caption **ADDRESSES.**

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration proposes to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

Pratt & Whitney Canada: Docket No. 2000–NE–24–AD.

Applicability: Pratt & Whitney Canada (P&WC) Model PW305 and PW305A turbofan engines, with stage 4 low pressure turbine (LPT) disks, part numbers (P/N's) 30A1457 and 30A1499. These engines are installed on but not limited to British Aerospace BAe. 125 1000A, BAe. 125 1000B, Hawker 1000 and Learjet 60 series airplanes.

Note 1: This airworthiness directive (AD) applies to each engine identified in the preceding applicability provision, regardless of whether it has been modified, altered, or repaired in the area subject to the requirements of this AD. For engines that have been modified, altered, or repaired so that the performance of the requirements of this AD is affected, the owner/operator must request approval for an alternative method of compliance in accordance with paragraph (c) of this AD. The request should include an assessment of the effect of the modification, alteration, or repair on the unsafe condition addressed by this AD; and, if the unsafe condition has not been eliminated, the request should include specific proposed actions to address it.

Compliance: Required as indicated, unless accomplished previously.

To prevent premature LPT disk failure due to cracking of the LPT disks, which could result in an uncontained engine failure and damage to the airplane, accomplish the following:

New Stage 4 LPT Life Limit

(a) Remove stage 4 LPT disks, P/N's 30A1457 and 30A1499, prior to exceeding the new life limit of 4000 cycles-in-service (CIS).

(b) Except for the provisions of paragraph (c) of this AD, no parts, identified by P/N in paragraph (a) of this AD, that exceed the new life limit of 4000 CIS, may be installed.

Alternative Method of Compliance

(c) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Engine Certification Office (ECO). Operators shall submit their request through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, ECO.

Note 2: Information concerning the existence of approved alternative methods of compliance with this airworthiness directive, if any, may be obtained from the ECO.

Ferry Flights

(d) Special flight permits may be issued in accordance with §§ 21.197 and 21.199 of the Federal Aviation Regulations (14 CFR 21.197 and 21.199) to operate the airplane to a location where the requirements of this AD can be accomplished.

Issued in Burlington, MA, on November 9, 2000.

David A. Downey,

Assistant Manager, Engine and Propeller Directorate, Aircraft Certification Service.

[FR Doc. 00–29379 Filed 11–15–00; 8:45 am]

BILLING CODE 4910–13–U

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: Proposed rule.

SUMMARY: This proposed 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. Also, it identifies circumstances when we may consider special royalty relief outside our established end-of-life and deep water royalty relief (DWRR) programs.

DATES: We will consider all comments we receive by December 18, 2000. We will begin reviewing comments then and may not fully consider comments we receive after December 18, 2000.

ADDRESSES: If you wish to comment, you may mail or hand-carry comments to the Department of the Interior, Minerals Management Service; Mail Stop 4024; 381 Elden Street; Herndon, Virginia 20170–4817; Attention: Rules Processing Team (RPT). The RPT's e-mail address is: *rules.comments@MMS.gov.*

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

SUPPLEMENTARY INFORMATION: The OCS Lands Act (43 U.S.C. 1337 *et seq.*) is the basis for our regulations on suspending or lowering royalties on OCS leases. This rule describes how certain new deep water leases may qualify for royalty suspensions and what circumstances might cause us to grant royalty relief outside normal procedures.

Background

The regulations at 30 CFR part 203 implement the Secretary of the Interior's (Secretary) authority to grant royalty relief to OCS leases. Section 302 of the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 (Pub. L. 104–58) (the Act), gave us the authority to promote development and production of marginal resources in certain areas by suspending royalties. Existing regulations describe our programs in three discretionary relief situations—leases nearing the end of their life, new developments in water 200 meters or deeper (deep water) in the Gulf of Mexico (GOM), or deep water expansion projects in the GOM. Our programs balance the effectiveness of royalty relief to encourage production that otherwise would not occur with receipt of fair market value for public resources in the specific circumstances of the individual leases.

Discretionary Relief To Promote Future Deep Water Development

Promotion of development with discretionary royalty relief serves several public purposes. In marginal circumstances, royalty suspension can encourage development of resources that otherwise might be bypassed. Royalty suspension can also lead to new production that uses existing infrastructure. Further, making relief discretionary avoids the need to offer blanket relief to whole categories of leases, many of which do not need it to attract exploration or development interest.

The Act contained the following provisions relating to DWRR:

• It authorized granting royalty relief both to nonproducing leases and to expansion projects on producing leases issued before adoption of royalty suspension in lease terms (pre-Act leases).

• It directed that we implement this authority in deep water (200 meters and greater water depth) because of the greater costs and economic risks involved in operating at those depths than in shallower water.

• It set out a qualification test intended to grant relief only when development otherwise would not make economic sense.

Based on the Act, our current regulations governing pre-Act leases oblige us to consider each field in its entirety. That approach commits us to evaluating all the resources that the field may contain. To improve the assumptions that we have to make, we propose to add language to invite applicants to share information they may have on other leases that may eventually become part of the field. (See clarifications we propose in § 203.63) Also, we propose to add language to clarify the reservoir and well data we are looking for in the geological and geophysical (G&G) report part of the application. (See changes proposed to § 203.86) Both of these proposed changes reflect additional information we have requested from previous applicants.

After November 2000, we will issue new deep water leases. Some will be like pre-Act leases in that we will issue them with no royalty suspension (RS) volume. Others, which we call RS leases, will have a royalty suspension included in the lease terms. In some circumstances, the size of the royalty suspension in the lease may be inadequate to induce development. For instance, stand-alone development of a marginal prospect may require more relief than a royalty suspension designed for a tie-back development. Because may of the special risks associated with deep water development remain, we propose to offer all leases issued in sales after November 2000 (post-2000 deep water leases) the opportunity to qualify for enough royalty suspension to make a development project or an expansion project economic. Deep water leases issued after the date of enactment of the Act and prior to November 28, 2000 (eligible leases), may not apply for royalty relief beyond the eligible amount specified in the lease.

Since the minimum suspension volumes set in the Act do not apply to leases issued in sales held after November 28, 2000, we propose to offer royalty suspension volumes on a project rather than a field-basis for post-2000 deep water leases. Specifically, any future deep water lease that lies west of 87 degrees, 30 minutes west longitude in the GOM may apply for royalty suspension on a development project if it had not produced, or on an expansion project if it has produced. Hereinafter, unless otherwise specified, reference to a ''project'' includes either a development of an expansion project. (See the new applicant category we add in proposed changes to § 203.60.)

The Act established a deadline by which we must evaluate a DWRR application for a pre-Act lease. The deadline helps development planning by giving applicants certainty about how long they can expect to wait for our relief determination. When companies have other investment opportunities, that planning certainty may be an important factor for keeping a marginal project alive. We plan to retain this deadline as a commitment for applications for post-2000 deep water leases. The Act also sets a default royalty suspension in the event we fail to act in time on an application. We propose to adopt a default royalty suspension amount that reflects the length of the delay, rather than the fixed default amount set by the DWRR Act for pre-Act leases. Specifically, if we fail to render a DWRR determination within 180 days (plus authorized extensions), a project on a post-2000 deep water lease will produce royalty-free for the number of months we delay a decision, plus the entire volume which our belated decision grants. (See the proposed new category we add to the table in § 203.66.)

Adjustments to Our DWRR Program

We have considered six DWRR applications over 4 years under the existing rules in 30 CFR part 203. During those evaluations, we identified some program elements that may produce results contrary to our intentions. We will therefore adjust provisions on minimum suspension volumes, sunk costs, discount rates, performance conditions, and allowable price increases while we modify these rules to authorize applications for royalty suspension by leases issued in OCS sales after November 2000.

Adjustments to Minimum Suspension Volumes and Relief Shares

Except for an application involving a pre-Act lease on a field that did not produce before the Act, we propose to reduce the minimum suspension volumes for DWRR we grant to nonproducing leases. The field-sized minimums established in the Act will continue to apply to qualifying applications that involve pre-Act leases. Congress based those original minimums on cost and producibility estimates from the early 1990's for field development. Since then, improved knowledge of deep water resources, technical progress, and new infrastructure have significantly reduced the size necessary for an economic prospect. As early as February 1996, the ''Oil and Gas Journal'' reported that industry experts believe the economic threshold for developing deep water projects had dropped from the 150 million barrels of oil equivalent (MMBOE) range to the 30 to 35 MMBOE range because deep water fields were proving more prolific and less troublesome than fields on the near-shore shelf. The fact that the Act's minimum suspension volumes exceed the expected resource sizes (in some cases by a large margin) in all but one of the deep water field applications we have reviewed, reflects the change in economic threshold.

We propose to offer more appropriate minimum royalty suspension volumes for development projects and for expansion projects that qualify for relief. For a development project on a pre-production RS lease, the minimum will equal the royalty suspension volume with which we issued the lease, plus an increment explained in the following section on sunk cost. As explained in our companion proposed rule modifying 30 CFR part 260, published on

September 14, 2000 (65 FR 55476), we plan to update the royalty suspension volumes with which we issue RS leases over time as needed. We also propose to offer a minimum suspension volume to expansion projects and to development projects on leases issued with no royalty suspension volume in sales after November 2000. The minimum for these projects will equal the increment explained in the next section on sunk cost.

When multiple nonproducing RS leases participate, the minimum volume suspension for the project equals the sum of the royalty suspension volumes applicable to the participating leases plus the increment explained in the next section. As with an expansion project, the applicant defines the scope of the development project, and relief applies only to wells included in the application. We reserve the right, as we do under the current program, to remove nonprospective wells or leases from the evaluation. (See the proposed new paragraph and conforming changes in § 203.69.)

With one exception, all leases participating in a successful application for DWRR share the single relief volume we approve. If the application involves a pre-Act lease, the single volume must at least equal the field-sized minimum set in the Act and applies to all production from the field. In these cases, we evaluate field rather than project economics, and all lessees share the volume we grant to the field.

If the application involves only post-2000 deep water leases, the single relief volume equals the amount we judge necessary to make the project economic. In this case, the royalty suspension replaces any suspension volume in the lease instruments and only applies to the reservoirs identified in the application. Thus, should a qualifying project fail to produce the full royalty suspension volume we grant in response to an application, the leases that participated in the application may not apply the unused volume suspension to other production. To do otherwise encourages understatement of a lease's potential in the application we review. If no production has occurred from the participating leases, the royalty suspension volume is subject to the minimum applicable for the development or expansion project.

The one exception to sharing a single volume occurs when an eligible lease is part of the field, In that instance, the eligible lease may produce royalty-free up to its field-sized suspension volume, regardless of the volume we set for the project proposed by the other leases. However, production from a development project on the same field counts against the field-sized volume available to the eligible lease.

We reflect these principles by adding the new applicant category in the proposed changes to § 203.71.

Adjustments to the Evaluation Elements

Except for cases that involve fields with a pre-Act lease, we propose to change the way we count sunk costs in the determination of whether an application qualifies for royalty relief. To comply with the Act's instruction to consider historic costs for pre-Act leases, we originally included the costs of and after the discovery well when calculating whether a field appeared economic, but only on fields where no production had yet occurred. We now propose to allow the documented costs of the discovery well, both for development projects on post-2000 deep water leases and for expansion projects on pre-Act or on post-2000 deep water leases. The discovery well is the one that penetrates the first reservoir targeted by the project and that meets the well producibility requirements of 30 CFR part 250. We expect that allowing sunk costs for this broader scope of prospects will help promote exploration in deep water and greater use of the opportunity to obtain supplementary royalty suspension volumes. Allowing some sunk costs to more applicants permits more leases to quality for royalty relief and thus encourages more exploration.

Unlike the treatment of sunk costs on pre-Act leases, we do not intend to count pre-application costs subsequent to the discovery well. This more limited treatment reflects a balanced approach to competing considerations. On the one hand, overcoming the unusual risks of deep water development may depend on Government sharing some of the uncertainty burden, even on expansion projects. Also, our regulations require only a discovery well before we will consider an application. Further, the uneconomic level for development projects will be lower because determination of whether the project qualifies for a supplemental volume suspension includes the value of any volume suspension with which we issued the participating leases. On the other hand, only future costs, not historic costs, influence decisions on whether to proceed on a specific project. Further, activities and costs other than the discovery well, such as acquiring seismic data, completing engineering studies, or drilling additional wells, are conducted at the applicant's discretion before filing an application for royalty relief. Additionally, costs associated with these other activities are more likely than a discovery well to benefit other prospects for help attract other partners or successor owners to this prospect. Counting only the cost of the discovery well balances sharing the exploration risk with the responsibility to include only relevant costs. (See the new category of sunk cost treatment proposed in the table in § 203.68.)

We do not propose to change the exclusion of sunk cost from the determination of how much relief a project needs to become economic (volume test). To do otherwise risks adding relief well beyond that necessary to make development economic. Also, it directs more relief to just the wrong projects, specifically those that are more likely to continue anyway because they have relatively smaller costs left to incur and that must be covered by future production. However, we will ensure that inclusion of sunk cost in the qualification determination gives the applicant an unambiguous benefit. We propose to do that by adding an increment of royalty-free production to any royalty suspension volume with which a qualifying project starts the application process. Our qualification test does factor in the volume suspensions with which we issued leases participating in the application, but not this increment.

We propose to set this increment at 10 percent of the most likely resource size we agree is appropriate for the project. For instance, consider a development project that MMS agrees has a most likely resource size of 60 MMBOE. If it qualifies for relief and is located on RS leases that we issued with a combined royalty suspension volume of 20 MMBOE, it will get a royalty suspension of at least 26 MMBOE. An expansion project in this situation would get at least 6 MMBOE.

This form of increment improves on a universal fixed increment or one tied to water depth because it is project-specific. Further, its relatively small size ensures that it neither provides too much or too little relief to encourage individual project development and program-wide exploration. It is preferable to a time-based increment, such as an extra year of royalty-free production, because it does not risk damaging ultimate recovery by creating an incentive to accelerate production to avoid royalties. A sub-marginal project may need royalty suspension for anywhere from a small fraction of its reserves to virtually all of them to be worth developing. If something less than royalty-free production of 50 percent of reserves on average justifies development on a look-forward basis (excluding sunk costs), a fraction of that could be safely provided to induce exploration. The 10-percent share represents a considered amount designed to encourage exploration on future projects deemed marginally or sub-marginally profitable. This policy leaves up to 90 percent of the project's production still subject to royalties.

Thus, the project-specific increment serves as a uniform replacement for sunk cost in the volume determination test. This increment assures any project that qualifies for supplemental relief because of sunk cost will have an additional volume suspension on top of what it has already. A development or an expansion project, therefore, may get a somewhat larger volume suspension than it needs to be economic on a look-forward basis. Alternatively, the project would get a larger volume than the minimum volume suspension if our evaluation indicates it needs more relief than the minimum to be economic on a look-forward basis. (See changes in § 203.69.)

To help us evaluate the effects of revising our treatment of sunk cost, we would like your comments on the following questions.

- How does a credit for sunk costs change your incentive to explore a risky prospect and to apply for royalty relief?
- What other treatments of sunk costs promote exploration without resulting in excessive volume suspension for many projects?

Also, we propose to lower the viability standard we set as a prerequisite to evaluating a field's or a project's need for relief. Our current evaluation procedure requires that the application meet two economic criteria. First, the application must show that a field or project is viable, i.e., would be economic assuming it paid no royalties and no sunk costs. Second, qualification for relief requires that the application show a nonproducing field would not be profitable assuming it paid certain sunk costs and full royalties, or that an expansion project would not be profitable paying full royalties. We have revised § 203.67 to clarify the dual criteria for qualification.

Until now, we insisted that the same discount rate be used for both the viability and the profitability estimates. While ensuring that the application does not give an overly pessimistic portrayal of the field or expansion project, this equivalence of discount rates may be too restrictive. Development without royalty or sunk costs should be less risky than if these costs have to be covered. Thus, the cost of capital under the viability circumstances should be lower than when full royalties and sunk costs must be paid. To acknowledge this potential difference, we propose to accept applications that demonstrate fields or projects have a positive value at a 10-percent real rate of discount. Applicants retain the right to set the discount rate we use for the profitability test at any value between 10 and 15 percent. (See changes to the guidelines that accompany § 203.67.) The MMS website, *www.gomr.mms.gov/homepg/offshore/royrelef.html*, provides the most current version of these guidelines, including the parameters we prescribe for discount rates and prices.

This change in our discount rate procedure offsets one effect of changing the way we treat sunk costs, for leases other than pre-Act leases, in our qualification determination. A 10-percent discount rate has the effect of raising the estimated present value of the field or project in the absence of royalties. Past applicants always chose a 15-percent discount rate. We anticipate that future applicants will continue to choose the maximum allowed discount rate for the full royalty profitability analysis. Thus, while limiting sunk costs generally reduces the difference between the viability and profitability estimate, a lower discount rate for the viability estimate than for the profitability estimate will increase this difference. The larger difference allows a wider range of circumstances to qualify as marginal fields or projects in need of royalty relief. More generally, limiting sunk costs for post-2000 deep water leases and acknowledging that development risks may be different with and without royalties makes our evaluation of economic need more realistic.

Finally, we are proposing to add language that clarifies what we seek in the administrative and design parts of an application. As with the G&G report, these changes reflect additional information we have requested from previous applicants. (See changes proposed to §§ 203.83 and 203.87.)

Adjustments to Post-Evaluation Elements

We propose adjustments in several of the conditions successful applicants must meet to realize a royalty suspension or to re-apply for relief. We propose adjustments in the deadline to start fabrication of the development system, in correcting for overestimating costs in the application, and in what constitutes an appropriate reason for us to reconsider the need for relief. These three proposed adjustments apply to all fields or projects seeking a volume suspension after the effective date of these revisions. Also, we propose to specify in the leasing documents the price thresholds (which we identify at the time of lease sale) above which we will suspend any remaining royalty relief for post-2000 deep water leases.

Current regulations require applicants to give evidence of a timely commitment to development by starting fabrication of their production facility within 1 year after we approve their application. We established this deadline to avoid premature applications. Requiring that projects or developments be ready to commence soon after approval means we make the relief decision close to the same point and with about the same quality of information as the applicant uses to make the commitment decision. While the fact that the ability to get into production quicker than expected partially accounts for the improvement in deep water economics, the 1-year-to-fabrication deadline we set needs lengthening. Shortages of drilling, design, and fabrication capacity for deep water development may make meeting the currently required schedule difficult. Also, we don't want to encourage token actions that don't really signal the start of development. Thus, we propose to lengthen the period when fabrication must start to 18 months after relief approval. Added to the 6-month period we use for evaluation, that gives a full 2 year lead-time between application and commitment to development. With our authority to extend that period for up to 6 months for events beyond the applicant's control, we feel this change should provide ample time to make the necessary arrangements to start development on projects or fields that receive royalty relief. (See change to deadlines proposed in § 203.70.)

Along with this deadline change, we propose to clarify that the meaning of "starting fabrication" requires continuous fabrication. Starting and then suspending fabrication of the production facility does not fulfill this performance condition. (See the addition we propose in § 203.76(b)).

Another performance condition we use to help ensure we deal with a realistic application has to do with estimated costs. We require actual expenditures to equal at least 80 percent of the costs that the applicant estimates spending. Both estimated and actual figures cover the period between the application and first production. The current correction for overestimating actual costs by too much is retention of only half of the volume suspension we originally granted. This correction has no real effect when the minimum suspension volume prescribed by the Act more than doubles the field's expected production. Thus, we propose to adjust the correction volume to retention of the smaller of one-half of the granted suspension volume or one-half of the most likely production specified in the application. (See changes to a deadline and the relief correction amount proposed in § 203.76.)

In conjunction with this change, we also propose to broaden what constitutes a development system. For instance, we will no longer consider Spars and mini-tension-leg platforms different development systems. Both are essentially floaters with export pipelines and little if any storage capacity. With this change, we intend to maximize the flexibility applicants have to entertain bids for competing versions of the same basic development system.

We also propose to expand the situations in which fields or projects may seek a redetermination of our initial relief decision. We provide more flexibility for allowing redeterminations when relief is withdrawn or relinquished. Also, we add another condition in which we permit a redetermination if we deny your application or you seek to increase an approved volume suspension. In these instances, in addition to substantial increases in estimated costs, reductions in expected prices, or new geologic information on the field, we propose to allow a re-application for a change of development system under certain conditions. It must be clear that the original application did not consider or deem the new development system infeasible. This situation might arise because new technology becomes available or a new owner with a different perspective takes over field development after the initial application. In either case, the new application needs to demonstrate that the new approach more efficiently develops the resource than what we originally evaluated. By more efficient, we mean either clearly lower costs or clearly larger recovery, so that estimated profit would increase under the circumstances we previously evaluated. (See the new fourth condition and the removal of the restriction on the price condition in the changes we propose to § 203.74.)

More realistic performance conditions may add value to the successful applicant's explicit right to renounce relief. Several successful past applicants have lost relief because they violated a withdrawal condition. Rather than wait until we formally withdraw relief, they could have renounced relief as soon as they realized they needed to change the proposed development system or significantly revise cost estimates. By renouncing, they could accelerate the start of a redetermination, thereby converting after-tax, sunk costs on authorized fields to before-tax, post-application costs for purposes of the next application. We propose to simplify § 203.77 to avoid confusion about this right.

Further, we propose to review the level we set and to which prices must rise before the need for royalty relief, granted under an earlier expectation of lower prices, disappears. By 1999, the Act's escalation procedure meant that oil prices must exceed $30/bbl or natural gas prices must exceed $3.80/MMBtu for an entire calendar year before pre-Act leases with a remaining volume suspension owe royalty. For comparison, royalties reduce realized price by slightly less than the royalty percentage, e.g., 12.5 percent for deep water tracts in greater than 400 meters (m) of water. When market prices rise above levels that prompted development by more than that percentage for at least a year, the need for the royalty suspension incentive disappears, at least for these projects or fields. Therefore, we propose to suspend royalty relief for projects when prices rise and remain substantially above levels prevalent when we approved relief. To reflect evolving market conditions, we will set these threshold levels in the Notice of Sale and lease documents associated with each future lease. (See the proposed changes that add the new relief recipient category to § 203.78.)

Finally, we propose to make clear in the regulations that we want a Certified Public Account (CPA) not affiliated with the applicant to vouch for the historic data in the application and post-production report. Thus, we have added the word ''independent'' before CPA in changes proposed to §§ 203.81 and 203.91.

The following table summarizes the elements of the current DWRR program that we propose to modify with this rule.

PROPOSED MODIFICATIONS TO DWRR APPLICATIONS

Element	Current and continuing program Applies to pre-Act leases	Proposed changes Applies to post-2000 deep water leases
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 recovery equals the suspension volume
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 reserves.
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 cost of only the discovery well, except when the application involves a pre-Act lease.
Threshold oil and gas price levels for lifting relief.	Statute sets threshold price for light sweet crude oil and natural gas.	Lease terms set threshold price for light sweet crude oil and natural gas.

PROPOSED MODIFICATIONS TO DWRR APPLICATIONS

Element	Current and discontinuing program Applies to pre-Act leases	Proposed 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 or smaller of granted suspension volume or most likely resource size.
Minimum suspension volume for expansion project.	None	10 percent reserves.
Credit for sunk costs in application for expansion project.	None	After-tax cost of the discovery well.

Royalty Relief in Special Circumstances

Certain circumstances can make leases ineligible for one of our established royalty relief programs. Yet, royalty relief may benefit both the lessee and the Federal Government. For example, a recent, significant renovation of operations prevents a lessee from seeking end-of-life royalty relief, at least temporarily. Or, the operator of a marginal expansion project in less than 200m of water cannot apply for a royalty suspension, even if it is located in the central and western GOM. When combined with other circumstances, such as a sudden drop in prices or unusually high original royalty rates, this ineligibility could cause substantial resources to be left unproduced. Some form of royalty relief in these unusual situations can serve the statutory purpose of increasing production or promoting development outside our established programs. Because of the rarity of situations that meet these unusual conditions, we will not establish another formal royalty relief program. But, we leave open the opportunity for an operator to request relief in special circumstances. Before evaluating a special relief application, we require that applicants establish eligibility. An applicant does this by gaining our approval that their situation meets several of the tests listed in the new § 203.80. Once that is done, we will establish case-by-case qualification conditions and relief format appropriate to the special circumstances.

Can you suggest forms of royalty reduction that we are not now using that might encourage increased production in the special circumstances we propose in § 203.80?

Procedural Matters

Public Comment Procedure

Our practice is to make comments, including names and home addresses of respondents, available for public review during regular business hours. Individual respondents may request that we withhold their home address from the record, which we will honor to the extent allowable by law. There may be circumstances in which we would withhold from the record a respondent's identity, as allowable by law. If you wish us to withhold your name and/or address, you must state this prominently at the beginning of your comment. We will not consider any anonymous comments. We will make all submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, available for public inspection in their entirety.

Regulatory Planning and Review (Executive Order 12866)

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

a. This proposed 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 certain new deep water leases may quality 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 quality for royalty relief in any one year, and the annual value of the relief will be less than $100 million. The only field that has gone into production after approval may, depending on prices, avoid slightly over $7 million in royalty payments in is first year of production. The royalty suspension options in this proposal will encourage new production from a few marginal leases. Because royalty suspension volumes are an incentive to production, they likely will have a beneficial effect on the offshore oil industry, domestic oil and gas supplies, and jobs. In fact, this program should increase aggregate OCS production by making production from marginal fields more economically feasible.

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

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

d. This proposed rule does not raise any novel legal issues, but does raise policy issues. The proposed 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 deep water leases. Also, it modifies some conditions under which lessees of pre-Act leases obtain royalty relief. In addition, the proposed action describes special circumstances under which lessees may apply for royalty relief that were not specified in our previous regulations. 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 proposed rule will not have a significant adverse economic effect on offshore lessees and operators, including those that are classified as small businesses. The proposed rule extends the benefit of discretionary royalty relief to certain OCS leases issued after November 2000 that qualify as marginally uneconomic. In any one year, we are likely to receive only a small number of royalty relief applications, which limits the number of entities the proposed 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 proposed 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 Standard Industrial Classification code 1381, Drilling Oil and Gas Wells, MMS estimates that a total of 1,380 firms drill oil and gas wells onshore and offshore. Of these, approximately 130 companies are offshore lessess/operators, based on current estimates. Publicly available data indicate that 39 companies qualify as large firms according to SBA criteria, leaving up to 91 companies that may qualify as small firms with fewer than 500 employees. However, because of the extremely high cost and technical complexity involved in exploration and development in deep water, the vast majority of lessees/operators that will be affected by this rule will be large companies. Of the 211 deep water leases that have 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, 2 of the 16 past applications we received have been from small operators. This rule proposes continuing 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 proposed 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 on the basis of a fully identified project rather than a whole, often incompletely identified field. Consequently, applicants may need to provide less extensive G&G data. For instance, we will not require them to submit data they have access to 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 have to 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 determination. While significant new geologic information or price or cost changes still enable a redetermination, applicants may now 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 already processed.
- Third, under the proposed 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, like the other two, cannot be considered to impose a significant adverse economic effect on a substantial number of small business entities. If anything, all four changes ameliorate the existing applicant cost burden.

Your comments are important. The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness boards were established to receive comments from small businesses about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions of MMS, call toll-free (888) 734–3247.

Small Business Regulatory Enforcement Fairness Act (SBREFA)

This proposed rule is not a major rule under 5 U.S.C. 804(2), the SBREFA. This proposed rule:

a. Does not have an annual effect on the economy of $100 million or more. This proposed 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 that may cause us to grant royalty relief that were not covered in the current regulations. 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 little if any revenue. To the extent that royalty relief encourages new production, it benefits applicants, one-third of which in the past have been small business. But only one of the four fields for which we have approved relief has gone into production. We expect, however, that in any one year, this proposed rule will not have an annual effect on the economy of $100 million or more.

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 proposed 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 residents of the United States or companies incorporated in the United States. This proposed rule does not change that requirement, so it does not change the ability of United States firms to compete in any way.

Unfunded Mandates Reform Act (UMRA)

This proposed 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 proposed rule modifies some procedures in the existing regulation, describes how certain new leases may qualify for royalty suspensions, and specifies special circumstances that might cause us to grant royalty relief that were not considered previously. 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.

Takings Implications Assessment (Executive Order 12630)

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

Federalism (Executive Order 13132)

According to Executive Order 13132, this rule does not have Federalism implications. This rule does not substantially and directly affect the relationship between the Federal and State Governments. This rule affects the collection of royalty revenues from lessees in the deep water GOM, all of which is outside State jurisdiction. States have no role in this activity with or without this rule. This does not impose costs on States or localities. States and local governments play no part in the administration of the DWRR program.

Civil Justice Reform (Executive Order 12988)

According to 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.

Paperwork Reduction Act (PRA) of 1995

The information collection requirements in the proposed rulemaking remain unchanged from those currently approved by OMB, and a new 83–I submission is not required.

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. In 1998, OMB approved the information collection requirements in the current regulations under OMB control number 1010–0071.

Based on experience to date, MMS subsequently determined that the application filing fee schedule should be revised. In addition, the need became apparent for establishing a new fee to cover applications for ''special relief for marginal producing leases.'' Consequently, we initiated the process to obtain OMB approval of these changes to the information collection burden. We published the required 60-day **Federal Register** notice on May 11, 2000 (65 FR 30431). The comment period closed on July 11, 2000; we received no comments. We then submitted a request to OMB, and OMB approved the revised information collection burden with a current expiration date of September 30, 2003. The approved information collection burden is consistent with the proposed amendments to the regulations.

As part of our continuing effort to reduce paperwork and respondent burdens, we invite your comments on any aspect of the reporting burden in part 203. MMS will address comments on the information collection burden in the final rule preamble. Refer to the **ADDRESSES** section for mailing instructions. We specifically solicit comments on the following questions:

(a) Is the proposed collection of information necessary for MMS to properly perform its functions, and will it be useful?

(b) Are the estimates of the burden hours of the proposed collection reasonable?

(c) Do you have any suggestions that would enhance the quality, clarity, or usefulness of the information to be collected?

(d) Is there a way to minimize the information collection burden on those who are to respond, including the use of appropriate automated electronic, mechanical, or other forms of information technology?

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.

The following chart provides our estimated ''hour'' burden for part 203 regulations and the application and audit fee ''non-hour'' cost burdens authorized under § 203.3

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 can't sustain continued production (end-of-life lease).	2 Applications	100	200
	Application 2×$12,000=$24,000 [1] Audit 1×$10,000=$10,000		
Application—special relief for marginal producing lease (expect less than 1 per year—new category).	1 Application	250	250
	Application 1×$15,000=$15,000 [1] Audit 1×$10,000=$10,000		

Reporting or recordkeeping requirement 30 CFR Part 203	Application/audit fees Annual responses	Hours per response	Annual burden hours
§ 203.55 Renounce relief arrangement (seldom, if ever will be used; minimal burden to prepare letter).	1 Letter	1	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	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	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	40
	Application 1×$1,000=$1,000 No Audit		
Application—preview assessment (seldom if ever will be used as applicants opt for binding determination by MMS instead).	1 Application	900	900
	Application 1×$46,600=$46,600 No Audit		
Application—special relief for marginal expansion project or marginal non-producing lease (expect less than 1 per year—new category).	1 Application	1,000	1,000
	Application 1×$49,000=$49,000 Audit 1×$20,000=$20,000		
Redetermination	1 Redetermination	500	500
	Application 1×$32,000=$32,000 [1] Audit 1×$25,000=$25,000		
§ 203.70, 203.81, 203.90, 203.91 Submit fabricator's confirmation report	2 Reports	20	40
§ 203.70, 203.81, 203.90, 203.92 Submit post-production development report.	2 Reports [1]	50	100
§ 203.77 Renounce relief arrangement (seldom, if ever will be used; minimal burden to prepare letter).	1 Letter	1	1
§ 203.79(a) Request reconsideration of MMS field designation	4 Requests	400	1,600
§ 203.79(c) Request extension of deadline to start construction	1 Request	2	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	16
Total Annual Burden	22 Responses	N/A	8,650

Reporting or recordkeeping requirement 30 CFR Part 203	Application/audit fees		
	Annual responses	Hours per response	Annual burden hours
	Total Processing Fees=$345,600		

[1] 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 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).

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

According 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.

Clarity of this Regulation

Executive Order 12866 requires each agency to write regulations that are easy to understand. We invite your comments about how to make this proposed rule easier to understand, including answers to questions like the following:

(1) Are the criteria for obtaining royalty relief clearly specified?

(2) Are the procedures for obtaining royalty relief clearly described?

(3) Are the rules for determining royalty suspension volumes for the various categories of leases clearly stated?

(4) Are the conditions for obtaining royalty relief in special circumstances adequately specified?

(5) Does the proposed rule contain technical language or jargon that interferes with its clarity?

(6) Does the format of the proposed rule (grouping and ordering of sections, use of headings, etc.) increase or reduce its clarity?

(7) Would the proposed rule be easier to understand if it were divided into more, but shorter, sections?

(8) Is there anything else we can do to make the proposed rule easier to understand? Send a copy of any comments that concern how we could make this proposed rule easier to understand to: Office of Regulatory Affairs, Department of the Interior, Room 7229, 1849 C Street, N.W., Washington, D.C. 20240. You may also e-mail your comments to: Exsec@ios.doi.gov.

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: October 30, 2000.

Sylvia V. Baca,

Assistant Secretary, Land and Minerals Management.

For the reasons stated in the preamble, the Minerals Management Service (MMS) proposes to amend 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 adding ''Development project'' and ''Royalty suspension (RS) lease'' and revising ''Authorized field,'' ''Eligible lease,'' ''Expansion project,'' ''Fabrication (or start of construction),'' ''New production,'' ''Pre-Act lease,'' ''Redetermination,'' and ''Sunk costs'' 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 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 that:

(1) You propose in a Development Operations Coordination Document (DOCD); and

(2) Is located on one or more contiguous leases that;

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

(ii) Are located in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude; and

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

* * * * *

Eligible lease means a lease that:

(1) Results from a 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 pre-Act lease or a lease issued in a sale held after November 28, 2000. For a pre-Act lease, it must also involve a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well project, etc.).

Fabrication (or start of construction) means evidence of irreversible commitment to a concept and scale of development, including copies of a binding contract between you (as applicant) and a fabrication yard, a letter from 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 production resulting from lease-development activities on a current pre-Act lease or a lease issued in a sale after November 28, 2000, under a Development Operations Coordination Document (DOCD) or a Supplement approved by the Secretary of the Interior after November, 28, 1995, that significantly expands production.

* * * * *

Pre-Act lease means a lease that:

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

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

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

* * * * *

Redetermination means your request for us to reconsider our determination on royalty relief because:

(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) Results from a lease sale held after November 28, 2000;

(2) Is in a location or planning area specified in the Notice of Sale offering that lease; and

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

Sunk costs on an authorized field means the after-tax costs (as specified in § 203.89(a)) of exploration, development, and production that you incur after the date of first discovery on the field and before the date we receive your complete application for royalty relief. Sunk costs on an expansion project or development project means, and on an authorized field includes, the after-tax costs of the discovery well qualified as producible under 30 CFR part 250, subpart A. In no case does sunk cost include any pre-discovery activity costs or lease acquisition and holding costs such as cash bonus and rental payments. Discovery well costs include any tangible costs directly related to the well that you incurred prior to the discovery date. We count pre-application costs on an unescalated, after-tax basis.

* * * * *

3. Section 203.2 is revised to read as follows:

§ 203.3 When can I get royalty relief?

We can 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) Whose earnings cannot sustain production (*End-of-life lease*).	Would abandon otherwise potentially recoverable resources but seek to increase production significantly 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.)
(b) Located in a designated Gulf of Mexico (GOM) deep water area, and acquired in a lease sale before November 38, 1995, or after November 28, 2000, and you propose in a DOCD or supplement to expand production significantly.	Are producing and seek to make a substantial investment (e.g., a platform or subsea template) to increase ultimate resource recovery from the field or lease (*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 she 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 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 increase production significantly 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 eligibility conditions.	A royalty reduction in a size or duration that makes your lease or project economic. (See §§ 203.80.)

4. Section 203.4 is revised to read as follows:

§ 203.4 How to 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) Information elements required for applications in §§ 203.51, 205.62, and 203.81 through 203.89.

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) Confirmation elements required to retain royalty relief in §§ 203.70, 203.81 and 203.90 through 203.91.

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) Prerequisites for approval of relief in §§ 203.50, 203.52, 203.60 and 203.67.

Approval conditions	End-of-life lease	Deep water		
		Expansion project	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) Well can produce		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		
(6) Determined to be economic only with relief		X	X	X

(d) Prerequisites for a redetermination in §§ 203.52 and 203.74 through 203.75.

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) Characteristics of relief in §§ 203.53 and 203.69.

Relief rate and volume	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 preapplication 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 or higher 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 lease				X
(6) Amount needed to become economic		X	X	X

(f) Provisions for discontinuing relief in §§ 203.54 and 203.78.

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 lease document.		X		X

(g) Provisions for ending or reducing relief in §§ 203.55 and 203.76 through 203.77.

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

Relief Withdrawn or Reduced	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(2) Royalty rate is at the effective rate for the most recent 12 of past 15 months with qualifying amounts of production.	X			
(3) Conditions that we may specify in the approval letter in individual cases that actually occur.	X			
(4) Recipient does not submit post-production report that compares expected to actual costs.		X	X	X
(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?

Under conditions in §§ 203.61(b) and 203.62, you may apply for royalty relief 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 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. § 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.

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

A. The introductory paragraph is redesignated (a) and is revised as set forth below.

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

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 may submit data for these leases according to § 203.81.

* * * * *

(b) No, if your application seeks only project relief.

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 specific development project. * * *

* * * * *

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 or project within 180 days and evaluate a redetermination under § 203.75 within 120 days after we determine that is is complete.

* * * * *

10. Section 203.66 is 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, the conditions in the following table aply.

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 production during 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 or project economically viable. Your field or proejct 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 (allowable expenditures on and in some cases after the discovery well as specified in § 203.89(a)) 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 or project can become economic with any relief (see § 203.67).
(3) Not include sunk costs	how much suspension volume is necessary to make the field or project economic (see § 203.69(c)).
(4) Include sunk costs for the discovery well only.	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, we will not collect royalties on a specified suspension volume for your field. 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:

(1) For RS leases, is the sum of the volume suspensions with which we issued the RS leases participating in the application plus 10 percent of the most likely resource size we agree is reasonable for your project; and

(2) For other deep water leases issued in sales after November 28, 2000, is 10 percent of the most likely resource size we agree is reasonable for your project.

(c) If the application for the field 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 ''Royalty Suspension Areas Map'' and the ''Field Names Master List'' 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 suspension volumes equal 10 percent of the most likely resource size we agree is reasonable for your project plus any suspension volumes required according to § 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. The cumulative production is 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 tell you 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 applying leases in the field 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.

If—	Then—	And—
(2) We assign a pre-Act or post-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, you agree to toll the evaluation clock until you modify your application to be consistent with the new field, and we have an additional 60 days to review the new information.	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.	The assigned lease(s) may share the royalty—suspension we grant to the new field. If you do not agree to toll, we will reject your application due to inadequate information. But, an eligible lease(s) we assign to the field keeps its automatic suspension volume.
(4) We assign another operator's lease to your field while we are evaluating your application, you both agree to toll the evaluation clock until both of you modify your application to be consistent with the new field, and we have an additional 60 days to review the new information.	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.	The assigned lease(s) may share the royalty suspension we grant to the new field. If you 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 assign a lease to your field before you submitted the royalty relief application.	We will not change your field's royalty suspension volume.	The assigned lease will not share in the relief if it did not participate in the application.
(6) We reassign a well on a pre-Act, eligible, or post-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 assign 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 chapter (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 and 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 without royalty suspension to your field.	Your field's royalty suspension volume does not change.	The assigned 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-2000 deep water lease applies (along with the other leases in the field) and qualifies (subject to any suspension volume in the lease) 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.	All leases in the field share the royalty suspension volume if we approve the application; or the RS leases in the field keep their respective volumes if we reject the application.

(c) This paragraph applies to a project with 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 until 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, paragraph (b) and (c) are revised and redesignated paragraphs (c) and (d), and a new paragraph (b) is added to read as follows:

§ 203.70 When will MMS reconsider its determination?

You may request a redetermination after we withdraw approval or after you renounce royalty relief. 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 of our conditions must occur.

* * * * *

(b) You demonstrate in your new application that a technology not considered or deemed feasible in the original application most efficiently develops this field or lease.

(c) Your current reference price decreases by more than 25 percent from your base reference price as determined 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 oil and gas for the most recent 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 his 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 you 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, 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 within 18 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 most likely size of producible 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 this effect to the MMS Regional Director for the GOM.

19. In § 203.78, the introductory paragraph and paragraph (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, or in your original lease agreement for post-2000 deep water leases, you must pay full royalties as prescribed in this section.

* * * * *

(f) We change the prices referred to in paragraphs (a), (b), and (d) of this section during each calendar year after 1994. For pre-Act leases, these prices change by the percentage that the implicit price deflator for the gross domestic product changed during the preceding calendar year. For post-2000 deep water leases, these prices change as specified in the leasing instrument and 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 special 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. Before you may apply for special royalty relief, 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.

(b) Valuable facilities (e.g., a platform or pipeline that would be removed upon lease relinquishment) exist on the lease that we do not expect a successor lessee to use.

(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 listed in the following table that apply to your field. §§ 203.83 through 203.91 describe these reports in detail.

Required reports	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	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 inputs 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, with primary regard to including only eligible costs that are incurred during the qualification months and 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) Lessee's well designation, the API number, and the location 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 additions and revisions in changes C, D, and G read as follows:

§ 203.86 What is in G&G report?

* * * * *

(b) * * *

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

(c) * * *

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

(d) * * *

(8) Reserve/resource distribution by reservoir.

* * * * *

24. In § 203.87, paragraphs (a)(1) and (d) are revised to read as follows, and paragraphs (d)(1) and (d)(2) are removed.

§ 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 an engineering report?

* * * * *

(a) On an authorized field, sunk costs which are all your eligible post-discovery exploration, development, and production expenses (no third party costs), and include the eligible costs of the discovery well on the field. On an expansion project or a development project, sunk costs are just the eligible costs of the discovery well for the project. Report them in nominal dollars and only if you have documentation. We count sunk costs in an evaluation (specified in § 203.68) as after-tax expenses, using nominal dollar amounts.

* * * * *

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

§ 203.91 What is in an engineering report?

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

[FR Doc. 00–29372 Filed 11–15–00; 8:45 am]

BILLING CODE 4310–MR–M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[MA–081–7211b; A–1–FRL–6897–5]

Approval and Promulgation of Air Quality Implementation Plans; Massachusetts; Enhanced Motor Vehicle Inspection and Maintenance Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The EPA is proposing to approve a State Implementation Plan (SIP) revision submitted by the Commonwealth of Massachusetts. This revision establishes and requires the implementation of an enhanced inspection and maintenance program. In the Final Rules Section of this **Federal Register**, EPA is approving the Commonwealth's SIP submittal as a direct final rule without prior proposal because the Agency views this as a noncontroversial submittal and anticipates no adverse comments. A detailed rationale for the approval is set forth in the direct final rule. If no relevant adverse comments are received in response to this action, no further activity is contemplated. If EPA receives relevant adverse comments, the direct final rule will be withdrawn and all public comments received will be addressed in a subsequent final rule based on this proposed rule. EPA will not institute a second comment period. Any parties interested in commenting on this action should do so at this time. Please note that if EPA receives adverse comment on an amendment, paragraph, or section of this rule and if that provision may be severed from the remainder of the rule, EPA may adopt as final those provisions of the rule that are not the subject of an adverse comment.

DATES: Written comments must be received on or before December 18, 2000.

ADDRESSES: Comments may be mailed to David Conroy, Unit Manager, Air Quality Planning, Office of Ecosystem Protection (mail code CAQ), U.S. Environmental Protection Agency, EPA-New England, One Congress Street, Suite 1100, Boston, MA 02114–2023. Copies of the State submittal and EPA's technical support document are available for public inspection during normal business hours, by appointment at the Office of Ecosystem Protection, U.S. Environmental Protection Agency, EPA-New England, One Congress Street, 11th floor, Boston, MA and Division of Air Quality Control, Department of Environmental Protection, One Winter Street, 8th Floor, Boston, MA 02108.

FOR FURTHER INFORMATION CONTACT: Peter Hagerty, (617) 918–1049.

SUPPLEMENTARY INFORMATION: For additional information, see the direct final rule which is located in the Rules Section of this **Federal Register**.

Dated: October 27, 2000.

Mindy S. Lubber,

Regional Administrator, EPA-New England.

[FR Doc. 00–29219 Filed 11–15–00; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 81

[Docket WA–00–01; FRL–6902–6]

Clean Air Act Reclassification; Wallula, Washington Particulate Matter (PM_{10}) Nonattainment Area

AGENCY: EPA.

ACTION: Proposed rule.

SUMMARY: EPA proposes to determine that the Wallula nonattainment area has not attained the National Ambient Air Quality Standards for particulate matter with an aerodynamic diameter of less than or equal to 10 microns (PM_{10}) by the attainment date of December 31, 1997, as required by the Clean Air Act. EPA's proposed finding is based on EPA's review of monitored air quality data reported for the years 1995 through 1999. If EPA takes final action on this proposal, the Wallula PM_{10}