Thus, the advantages of incorporation by reference are realized and publication of the complete description of each SIAP contained in FAA form documents is unnecessary. The provisions of this amendment state the affected CFR (and FAR) sections, with the types and effective dates of the SIAPs. This amendment also identifies the airport, its location, the procedure identification and the amendment number.

The Rule

This amendment to part 97 is effective upon publication of each separate SIAP as contained in the transmittal. Some SIAP amendments may have been previously issued by the FAA in a National Flight Data Center (FDC) Notice to Airmen (NOTAM) as an emergency action of immediate flight safety relating directly to published aeronautical charts. The circumstances which created the need for some SIAP amendments may require making them effective in less than 30 days. For the remaining SIAPs, an effective date at least 30 days after publication is provided.

Further, the SIAPs contained in this amendment are based on the criteria contained in the U.S. Standard for Terminal Instrument Approach Procedures (TERPS). In developing these SIAPs, the TERPS criteria were applied to the conditions existing or anticipated at the affected airports. Because of the close and immediate relationship between these SIAPs and safety in air commerce, I find that notice and public procedure before adopting these SIAPs are impracticable and contrary to the public interest and, where applicable, that good cause exists for making some SIAPs effective in less than 30 days.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore—(1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. For the same reason, the FAA certifies that this amendment will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 97

Air Traffic Control, Airports, Navigation (Air).

Issued in Washington, DC on January 9, 1998.

Quentin J. Smith, Jr.,

Acting Director, Flight Standards Service.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me, part 97 of the Federal Aviation Regulations (14 CFR part 97) is amended by establishing, amending, suspending, or revoking Standard Instrument Approach Procedures, effective at 0901 UTC on the dates specified, as follows:

PART 97—STANDARD INSTRUMENT APPROACH PROCEDURES

1. The authority citation for part 97 is revised to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40113, 40120, 44701; and 14 CFR 11.49(b)(2).

2. Part 97 is amended to read as follows:

§§ 97.23, 97.25, 97.27, 97.29, 97.31. 97.33 and 97.35 Amended

By amending: § 97.23 VOR, VOR/DME, VOR or TACAN, and VOR/DME or TACAN; § 97.25 LOC, LOC/DME, LDA, LDA/DME, SDF, SDF/DME; § 97.27 NDB, NDB/DME; § 97.29 ILS, ILS/DME, ISMLS, MLS, MLS/DME, MLS/RNAV; § 97.31 RADAR SIAPs; § 97.33 RNAV SIAPs; and § 97.35 COPTER SIAPs, identified as follows:

...Effective January 29, 1998

New York, NY, John F. Kennedy Intl, ILS RWY 4L, Amdt 9

...Effective February 26, 1998

Ames, IA, Ames Muni, GPS RWY 13, Orig
Ames, IA, Ames Muni, GPS RWY 19, Orig
Plymouth, MA, Plymouth Muni, GPS RWY 6, Amdt 2
Worcester, MA, Worcester Regional, GPS RWY 29, Orig
Morris, MN, Morris Muni, GPS RWY 32, Orig
Lebanon, NH, Lebanon Muni, ILS RWY 18, Amdt 4
Manville, NJ, Central Jersey Regional, VOR OR GPS–A, Amdt 6
Manville, NJ, Central Jersey Regional GPS RWY 7, Orig
Newark, NJ, Newark Intl, ILS RWY 4R, Amdt 10
Fredricksburg, VA, Shannon, NDB RWY 24, Amdt 2
Fredricksburg, VA, Shannon, GPS RWY 24, Orig
Appleton, WI, Outagamie County, NDB RWY 29, Amdt 1
Appleton, WI, Outagamie County, ILS RWY 29, Amdt 2
Wisconsin Rapids, WI, Alexander Field South Wood County, GPS RWY 20, Orig

Note: The following Standard Instrument Approach Procedures (SIAPs) published in TL 98–01 effective February 26, 1998, have been rescinded:

Yuma, AZ, Yuma MCAS-YUMA Intl, GPS RWY 17 Orig
Yuma, AZ, Yuma MCAS-Yuma Intl, GPS RWY 21R, Orig

...Effective April 23, 1998

Ashland, OH, Ashland County, VOR OR GPS-A, Amdt 8
Ashland, OH, Ashland County, NDB OR GPS RWY 18, Amdt 10
Georgetown, OH, Brown County, GPS RWY 35, Orig
Wilmington, OH, Airborne Airpark, ILS RWY 4L, Amdt 4
Wilmington, OH, Airborne Airpark, ILS/DME RWY 4R, Amdt 1A, CANCELLED
Wilmington, OH, Airborne Airpark, ILS RWY 4R, Orig
Wilmington, OH, Airborne Airpark, ILS/DME RWY 22L, Amdt 1, CANCELLED
Wilmington, OH, Airborne Airpark, ILS RWY 22L, Orig
Rice Lake, WI, Rice Lake Regional-Carl's Field, VOR RWY 1, Orig

[FR Doc, 98–1098 Filed 1–15–98; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 203

RIN 1010–AC13

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

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: This rule establishes conditions for reducing royalties on producing leases; provides for suspension of royalty payments on certain deep water leases issued as the result of lease sales held before November 28, 1995; and describes the information required for a complete application for royalty relief.

EFFECTIVE DATE: This rule is effective February 17, 1998. However, the information collection requirements contained in § 203.61 will not become effective until approved by the Office of Management (OMB). MMS will publish a document at that time announcing the effective date.

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

SUPPLEMENTARY INFORMATION:

I. Objectives of Royalty Relief

Royalty relief can lead to increased development and production of natural gas and oil, creating profits for lessees and royalty and tax revenues for the government that it might not otherwise receive. This rule establishes economic incentives that encourage Outer Continental Shelf (OCS) lessees to spend or invest the money needed to promote development and encourage increased production. For all Federal offshore planning areas, we may provide enough relief to allow a reasonable operating profit if expenses plus royalties are approaching revenues. For cases in certain deep water (water at least 200 meters deep) planning areas of the Gulf of Mexico (GOM), we may suspend royalty payments to permit lessees to earn a reasonable return on their capital investments.

The Secretary of the Interior (Secretary) carries out royalty relief as part of his stewardship and sound management of public lands. This includes conserving resources, getting a fair return to the public on OCS resources, and ensuring all OCS development is safe and consistent with sound environmental standards.

II. Legislative Background

The Secretary has broad legislative authority to reduce royalty rates on OCS leases. Section 8(a)(3)(A)of the Outer Continental Shelf Lands Act (OCSLA), as amended (43 U.S.C. 1337(a)(3)(A)), gives the Secretary authority to reduce royalties on leases in order to increase production. Relief must be justified and granted case by case.

On November 28, 1995, President Clinton signed Public Law 104–58, which included the Deep Water Royalty Relief Act (DWRRA). Section 302 of the DWRRA amends section 8(a) of the OCSLA (43 U.S.C. 1337(a)(3)(B)) authority so the Secretary may grant relief on a producing or non-producing lease, or category of leases. Its purpose is to promote development or increased production, or to encourage production of marginal resources, for GOM leases lying west of 87 degrees, 30 minutes West longitude.

The DWRRA also covers leases issued in water depths greater than 200 meters (deep water) as a result of sales held before the DWRRA's enactment. Section 302 of the DWRRA singles out ''new production'', from a lease or unit existing on the date of its enactment and in the GOM's deep water west of 87 degrees, 30 minutes West longitude. The amended OCSLA (43 U.S.C. 1337(a)(3)(C)) says this new production doesn't qualify for royalty suspension if the Secretary determines that this new production would be economic without royalty relief. Otherwise, the Secretary must determine for each case how much production to exclude from royalty in order to make the new production economic.

Existing leases or units having no royalty-bearing production, other than test production, before November 28, 1995, and qualified for relief under Section 302, need not pay royalties from a field on the first:

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

These leases or units may qualify for a larger suspension volume if this specified volume wouldn't make the field economic.

Under § 8(a) of the OCSLA as amended by § 302 of the DWRRA, we may also grant a royalty-suspension volume for production from lease development involving a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well projects, etc.) proposed in a Development Operations Coordination Document (DOCD), or a supplement to an approved DOCD, approved by the Secretary after November 28, 1995. This type of relief is available to leases that produced before November 28, 1995. In this case, we'll grant the suspension volume we determine necessary to make the new production economic.

We issued the Interim Rule for Royalty Relief for Producing Leases and Certain Existing Leases in Deep Water on May 31, 1996 (61 FR 27263). We asked for comments, received many, and are now issuing a final rule.

III. Response to Comments

Fifteen respondents—the American Petroleum Institute (API), the National Ocean Industries Association (NOIA), the Independent Petroleum Association of America (IPAA), and 12 oil and gas companies—submitted comments on the Interim Rule and the supplementary guidelines. We analyzed all comments and sometimes revised the final language based on them. We first address the general concern expressed about the Net Revenue Share (NRS) royalty relief system, followed by the three main themes raised in the comments on the Deep Water royalty relief system. Finally, we provide responses to the other individual comments and answer questions relating to selected provisions retained from the Interim Rule.

Comment on Utility of NRS Relief

Comment: The regulations dealing with NRS leases will be of little or no utility. Regarding leases with inadequate revenues to sustain production, the qualifying requirement stipulating that royalty payments must be at least 75 percent of net revenues over the most recent 12-month period is unrealistic and too stringent (§§ 203.50, 52 and 53).

Response: We've chosen to keep the two principal features of the proposed NRS system. These are a qualification requirement based on a 75 percent royalty share of net revenue and a feature whereby the average lease rate gradually rises back to the pre-relief level when production made possible by the relief rises sufficiently. However, we've made changes in this form of relief that will make it easier to implement and operate under the NRS system. These changes will reduce the application burden, simplify the qualification requirements, and modify the operational framework.

We proposed the NRS system to implement the OCS Lands Act (43 U.S.C. 1337(a)(3)(A)) authority to offer royalty relief to a producing lease to promote increased production. We specified different qualification conditions for two situations: end-of-life leases with inadequate revenues to sustain production and marginally economic projects to expand production. We've decided to no longer offer a separate form of royalty relief for expansion projects, because lessees with such projects should generally prefer applying for, and operating under, the revised end-of-life relief system in this final rule. Also, by dropping project relief we've simplified the program by eliminating the need for the applicant to show that production would be economic only with relief and that the project would add at least 1 year's worth of production. To emphasize this narrower scope and avoid confusion with an NRS system that has been generally avoided by industry, we've adopted the new name ''end-of-life relief.'' However, we have retained the underlying conceptual framework of the proposed NRS system in the new end-of-life royalty relief system.

For end-of-life situations, the interim rule required a demonstration that royalties were taking 75 percent of net revenues and were projected to take an increasing share in the future. We designed these stipulations to fulfill the ''increase production'' condition in the statute. However, we now believe that the increasing share requirement added little to the assurance that royalty relief would result in increased production. Also, it was burdensome and placed us in a position of relying unnecessarily on projections made by the applicant. Accordingly, we've dropped the increasing share condition.

Moreover, we've reduced the extent of information that must be submitted in an application. Instead of 36 months of cost history and 12 months of prospective data, under the new end-of-life system, applicants provide cost and production for the 12 out of the past most recent 15 months that have average daily production of at least 100 barrels of oil equivalent (BOE). Note the 100 BOE per day threshold applies to whole leases, not individual wells. The 12 out of 15 months provision protects producers from being disqualified by temporary shut down events like well work-overs, and it mitigates misrepresentations due to seasonal variation. The 100 BOE average daily production requirement gives us more assurance than the previous proposed ''increasing share'' requirement of the interim rule that relief would make the increased production economic. We believe that leases with production smaller than 100 BOE cannot cover platform operating costs and that they likely continue to operate for reasons beyond those that royalty relief would affect. That is, while royalty relief may reduce losses for under 100 BOE/day operators, it will not increase production from them.

The proposed NRS relief system took 50 percent of increases or decreases in net revenue, regardless of the cause. We designed this feature to allow the public to share automatically in unforeseen expansions of production, price increases, or cost decreases while cushioning lessee losses from unforeseen deterioration in these factors. The absence of applications suggests to us that these advantages were outweighed by a perception that the NRS system imposed on lessees a heavy and ongoing data collection burden and extracted from them too much of their upside profit potential.

Fortunately, we've found that a simpler and less burdensome royalty system can approximate the sliding rate structure of the NRS system. Therefore, we've replaced the NRS terms, which typically included a 50 percent rate over any possible level of production, with a 2-tier royalty rate. We give you relief with a rate fixed at one-half the pre-relief rate for a specific monthly amount of production followed by an incremental rate fixed at 50 percent above the pre-relief rate for production above that monthly amount. We added other features to balance the end-of-life system. Features that encourage lessees include a cap on the average royalty rate at the pre-relief rate and a lessee option to end relief at any time. Features that protect public interest include lifting of relief during periods of very high prices, an eventual end of relief if prices or production, or both, remain high for an extended period, and a provision allowing us to identify conditions in individual cases which would lead to terminating the relief arrangement because those conditions are inconsistent with an end-of-life situation.

Main Themes in Comments on the Deep Water Interim Rule

1. Qualification Circumstances

Comment: The current interim rule is too complex. As an alternative, API, NOIA, and IPAA suggest setting minimum economic field sizes (MEFS) by water depth and development system that automatically qualify fields for royalty relief (§ 203.67).

Response: Automatic MEFS are too impractical and difficult to develop and maintain. So, we won't use them to decide if a field qualifies for the amount of royalty relief the DWRRA specifies.

We estimate that calculating an MEFS requires values for more than 90 parameters, such as price, quality, water and drilling depth, gas-to-oil ratio, production rates, and scheduling of costs and production. We'd need to calculate many MEFS and would have to update them regularly as prices, costs and other significant values change. With large amounts of relief and rapidly changing values, and given the nearly explicit statutory mandate to provide sufficient relief, but not too much, we'd have to carefully set the qualifying field sizes. As a result, we'd not be able to set MEFS at sizes that would be worth developing even with royalty relief.

In contrast, the potential number of non-producing leases that may come in for relief looks relatively small. These are pre-Act leases, formerly pre-enactment deep water leases, or PDWLs. We can now identify fewer than 75 fields in this category, a small fraction of which may need relief. More importantly, we can't justify relying on generic data to determine an MEFS when an application gives us specific data for each field.

2. Early Relief Indication

Comment: MMS requires that a DOCD be approved before an applicant can submit a complete application for royalty relief on a pre-Act lease. Unfortunately, that pushes the request for royalty relief too late into development to be useful. Lessees won't prepare expensive DOCDs for projects that might not go into production, so they want some assurance royalty relief will be granted before preparing one (§ 203.83).

Rather than require an approved DOCD before submission of an application, break approval into two phases. In phase one, an applicant would file a preliminary application early in the life of a project based on the best information available at the time but with significantly less data than required in a final application. Based on a less extensive review than required for a final application, MMS would give a preliminary finding about whether the project qualified for relief and the appropriate suspension volume. Unless there were material changes, the preliminary finding would be binding. In phase two, a final application would either confirm the relief or cause MMS to do a new evaluation because of material changes (§ 203.61).

Response: We agree that the DOCD requirement is unnecessarily restrictive and have removed it in the final rule. Instead, we'll depend on other means to ensure appraisals are complete enough for the applicant to make an informed decision to develop and for us to evaluate the need for royalty relief. We will:

- Shorten the period allowed from 2 years to 1 year between the approval of relief and the start of construction on the development and production system,
- Allow significant new geological and geophysical (G&G) data to qualify only for the initial redetermination, and
- Use our own professional judgment on whether the appraisal is sufficient for decision making.

Breaking the approval into two phases as proposed by industry comments has a number of flaws. MMS would have to make a conditionally binding relief decision in phase one with less data and certainty than the company would have when it decides whether to develop after phase two. Foregoing Federal property rights to royalty income under the existing lease contract without sufficient information would be too arbitrary. Also, our conditional approval may discourage an applicant from developing more information that might change the preliminary finding, before filing a phase two application.

We've changed the rule to fit industry's request for an assessment of relief early in the project. In certain circumstances, a lessee or operator may request a nonbinding assessment of whether a field would qualify for royalty relief before submitting the first complete application on a field. This option will help those who don't want to risk having to meet qualifications for a redetermination if we reject a complete application, but want to know early about the chances for royalty relief on a marginal prospect.

The request would involve a draft application plus a processing fee. It could come any time after discovery (after a well qualifies under 30 CFR 250.11 or production is allocated under an approved unit agreement). The detail must be comparable to a complete application to ensure we assess the same prospect the lessee or operator envisions. We would develop a nonbinding assessment presuming that continued appraisal would produce expected values for unknown, but essential, data. Therefore, applicants must also send in an appraisal plan to drill one or more wells should MMS issue a favorable nonbinding assessment. After at least 90 days, a final, complete application can confirm or revise the data in the draft application and present the applicant's binding proposal as a condition for receiving royalty relief.

3. Complexity of Methods and Data Requirements

Comment: MMS proposes to use Monte Carlo simulations to account for the uncertainty in application data. Probability distributions in Monte Carlo techniques may be appropriate to analyze exploration and evaluate the adequacy of lease sale bids for which most data are unavailable and estimated. However, these approaches are less appropriate to analyze development. After discovering hydrocarbons, drilling delineation wells and taking seismic readings, the data are much more certain. Companies typically use simple scenario modeling and sensitivity analyses on development projects. MMS should adopt the scenario approach most used by industry (§§ 203.85–89).

Response: We've kept the Monte Carlo methods, though somewhat simplified, for several reasons. No clear milestones show when appraisal or delineation is adequate for making the development decision, so scenario modeling would not be suitable for many applications. Also, we must systematically handle the uncertainty associated with applications to be submitted at an early stage of development and we've been given a mandate to deal with the extra risk deep water poses. The Monte Carlo approach handles these diverse situations and requirements by allowing for the incorporation of as much or as little risk as perceived, a full range of sensitivity analysis, and the small but positive chance for all the circumstances an operation needs to become highly profitable.

We differ from the scenario approach industry describes mainly in the way we estimate reserves. The scenario approach offers no systematic way to arrive at a reserve size and chance of occurrence. We use careful descriptions of reservoirs and a standard procedure for calculating resources and aggregating them to the field level. Generally, we have adopted the reserves and resource definitions of the Society of Petroleum Engineers. This standardized procedure treats all applicants alike. It keeps our evaluators from having to learn the subtleties of each applicant's definition of reserves in order to verify and perhaps change that part of the evaluation. The level of detail proposed will ensure that we apply a consistent, analytically supportable method, especially for estimating producible reserves and resources.

The G&G report requests measurable reservoir data to help us validate inputs to the evaluation model. Distributions for all data items provide a way to document the uncertainty about these factors, but we don't need estimates for all data items because the model combines some items and derives other inputs. We've tried to clarify and simplify the data requirements in the spirit of the ''scenario'' approach.

Under our Monte Carlo procedure, applicants may use up to three discrete development scenarios, and they may include ranges for many of their variables. We need this detail so we can clearly understand the options and uncertainties an applicant faces. Our model has a less complex structure than publicly available models for estimating reserves and evaluating economics.

Individual Comments on the Deep Water Interim Rule and Guidelines

The following tables respond to the comments we received on the interim rule and supplementary guidelines. Each row references appropriate sections in the final rule and subject areas in the interim rule that relate to that comment and response.

COMMENT ON GENERAL PROVISIONS

Requirement/Subject	Comment	MMS Response
203.3/Processing Fees	The fees for royalty relief are too high and more than cover the costs of processing and deterring nuisance applications. Applicants should get refunds if fees are more than actual processing costs, which could be the case if screens for minimum field size are used to approve relief.	We estimate fees based on how many hours of work we expect the average application to take. After we have more experience with applications, we'll review processing costs and adjust fees if necessary. We plan to give refunds only for incomplete applications. But, we won't charge more when processing costs exceed the established fees.

COMMENTS ON NET REVENUE SHARE (NRS) ROYALTY RELIEF

Requirement/Subject	Comment	MMS Response
203.52/NRS Relief—Approval Criteria for Multiple-field Leases	If a lease produces from two or more fields, one or more of which do not qualify for NRS relief, royalty relief should still be possible for the lease production which would otherwise qualify.	Relief for end-of-life cases is designed for and granted to a whole lease or unit, not to a project or field. If a lease as a whole qualifies for end-of-life relief, it gets it regardless of how many fields are involved.

COMMENTS ON NET REVENUE SHARE (NRS) ROYALTY RELIEF—Continued

Requirement/Subject	Comment	MMS Response
Guidelines—Supplementing 203.53/Relief Operation	Requiring the operator to act as a single payor could not have been anticipated at the time the producer agreed to become the operator and exposes the operator to unforeseen legal implications or burdens. Getting money and accurate information to pay and report royalties from other lease owners is difficult, if not impossible, and could obligate the operator for late or improper payment and reporting interest and penalties.	Agree. We've dropped this requirement. It was proposed because the scope of an audit for a lease receiving royalty relief is greater than for normal leases. A single payor is designated to keep our audit expenses reasonable wherever multiple lease owners enjoy relief. However, the Royalty Simplification and Fairness Act contains language which precludes our insistence on a single payor.
203.56/NRS Relief—Lease Transfers or Assignments	If a lease is assigned, the NRS terms should be transferred to the assignee upon request. If the assignee doesn't ask to retain NRS terms, the lease should revert to the standard lease royalty rate.	In concept, relief is granted to a lease or unit, not to a lessee. We've changed the rule to automatically transfer relief terms to the assignee. Lessees also have the option to end relief at anytime.

COMMENTS ON DEEP WATER ROYALTY RELIEF (DWRR)

Requirement/Subject	Comment	MMS Response
203.60 & 78/Field Definition Decision Level & Appeals.	MMS should elevate the level for field definition decisions, notify lessees of the field designations, and allow them to object. It should also extend the period for appealing a field decision from 15 to 30–60 days. And it should allow companies to review current field designations for the GOM and industry input in any revisions	Agree in part. The Chief, Reserves Section, Office of Resource Evaluation, GOM Region (GOMR), will make field decisions after a lease has been qualified as producible. As part of that process, affected lessees and operators will be able to review and discuss any data with us before we make the final field decision. We won't extend the formal appeal period after this decision. Until the GOMR issues a final decision on the field designation, lessees of a pre-Act lease can't apply for DWRR. However, a DWRR application based on the GOM Regions' final field designation decision can be filed and processed while the field designation is under appeal.
203.60/Field Concept and Designation—Methodology.	Industry is accustomed to delineating a field for reasons of infrastructure, not geology, so disagreements over ''field'' designation can be expected. Recommend that MMS make public the methods it uses to identify fields and work with industry to develop a more precise definition for ''field.''	Agree. The term ''field'' in geological and petroleum literature is usually defined relative to geologic structure or stratigraphic conditions. The *Field Naming Handbook,* already available on the INTERNET from the GOMR, explains our methods. The GOMR will gladly entertain suggestions for improvements. Meetings on a field designation before starting the completeness review can improve understanding. But the basic entity for relief on royalties in deep water is the geologic field, not the project.
Deep Water Guidelines Supplementing 203.62/ Applications—Informal Consulting.	Will MMS answer questions on preparing an application before it is filed and a fee paid?	Yes. As the revised guidelines state, we'll informally advise you how to fill out an application, but not whether to file one. Given the extensive guidelines and model documentation, informal advice can save you time before filing and us time during the completeness review and evaluation.
203.62 & 65(f)/Applications & Revising Applicants' Assumptions.	The economic, geologic, and engineering reports are too complicated, voluminous, and costly for marginal opportunities that depend on royalty relief. But MMS should not revise any assumptions without consulting the applicant and, if necessary, letting a third party settle disputes. At the very least MMS should justify any revisions to an applicant's assumptions	Agree in part. Application requirements impose a small cost in comparison to the size of the royalty relief at stake. We'll use our judgment and discretion in deciding whether to ask an applicant for more information or for clarification before making any changes, tolling the clock as needed to complete a full evaluation. We also will identify changes in related variables that may need to be discussed. Where major assumptions are unsupported by backup or important data elements are inconsistent with other parts of the application, we'll fully explain the source of the problem and provide a chance to explain or resolve the outstanding issues before deciding on an application. We aren't planning to use third parties to resolve disputes.
203.63/Applications—Joint Application Difficulties.	Industry is pleased that DWRR doesn't mandate unitization. However, joint applications may be unworkable due to different reserve numbers, costs, etc., estimated by different lessees	If lessees want DWRR, they will have to at least design applications jointly and, if approved, make sure they meet performance conditions for retaining relief. In cases where a party refuses to cooperate in submitting a joint application, it won't be eligible to receive any relief granted, and we'll likely need to make assumptions about how it might have participated in and contributed to joint development of the field.

COMMENTS ON DEEP WATER ROYALTY RELIEF (DWRR)—Continued

Requirement/Subject	Comment	MMS Response
203.63/Applications—Joint Application Coercion.	MMS shouldn't require lessees that share the same geologic structure to file joint applications because this requirement could inhibit applications or restrict how companies operate offshore. For instance, on multi-lease fields, an economic project might negate another's less robust project; or a more advanced project may refuse to co-operate with a competitive, but lagging, project, etc	Joint applications don't require joint development, but they are an inescapable feature of a field-based system. The rules allow good-cause exceptions to joint applications. Should other lessees on the field choose not to apply for relief, they're still free to develop their leases as they wish, but they won't share any relief granted.
203.64/Applications with Assignments.	A limit of one application per field restricts a company from seeking relief on a farmed-out lease if the prior owner applied for relief on that field and was rejected. The new company that thinks it could develop the field with royalty relief must qualify for a redetermination to apply	The limit is intended in part to close the potential loophole of assigning leases to get around requirements for redetermination.
203.65/Review and Evaluation—Notification of MMS Determinations.	MMS should notify all affected lessees when royalty relief is granted and publish when, who, and how much relief is given	Agree. We will notify all designated lease operators within a field when royalty relief is granted. The basic summary information will be published on MMS's and GOMR's home pages on the INTERNET.
203.65/Review and Evaluation—Determination Period.	MMS's determination review is too long and will delay field development because lessees can't invest without knowing whether royalty relief will be available. Reduce the review time to 3 months	Public law sets the allowed review periods. However, we don't plan to use the entire time if we can do determinations faster. Yet careful review often requires time, especially when new and complex developments are proposed and huge amounts ($100 million plus) of royalty relief and taxpayer assets are at stake.
203.65/Review and Evaluation—Tolling the Clock—Measurement.	The clock should be tolled by using one measure of time, either work days or calendar days	DWRRA stipulated calendar days for its deadlines of 120 or 180 days for approval or rejection. We'll continue to use work days for reviewing applications for completeness because of the short time allowed. MMS must review each application thoroughly to ascertain whether it is complete before we start the statutory clock in calendar days to analyze economic viability. Industry is accustomed to our using work days to conduct completeness checks for other filings.
203.65/Review and Evaluation—Method for Tolling the Clock.	Evaluation time should be tolled ''upon receipt by the applicant of written notification'' of an information deficiency and the clock should be restarted ''upon receipt of the needed information in the [GOM] Regional MMS office.''	Agree. As the rule states, the evaluation clock will be stopped when the applicant receives written notice from us and will begin when the requested information is received in the regional office.
Deep Water Guidelines Supplementing 203.65/ Review and Evaluation—Consistency with Differences in Geologic Interpretation.	How will MMS account for costs and production (revenues) that it believes should be added to the economic evaluation of a field because they are associated with developing reservoirs omitted from an application?	Each application and scenario presents a unique proposal. We'll adjust data as necessary. For example, if we determine that an applicant omitted prospective reservoirs, it's reasonable to assume they'll be found and developed later. By adding the necessary costs after production begins, we avoid the complexity of having to adjust the estimated pre-production costs used as a performance condition.
203.67/Review and Evaluation—Dual Test Role in Evaluation Model (Royalty Suspension Viability Program (RSVP)).	Eliminate the dual test, at least for applicants seeking only the minimum suspension volume. MMS should grant relief and not interject itself into the process by which a lessee decides to develop and incur costs to bring a field into production	We've kept the dual test, but have modified the calculations to reflect industry concerns that our determinations may not always coincide with industry decisions, even using the same input data. If, under these altered conditions, the dual test indicates that no amount of royalty relief will make the field economic, we can reasonably infer that the application is missing some key factor in the decision to develop.
203.68/Review and Evaluation—Dual Test Treatment of Sunk Costs.	Because sunk costs aren't in the dual test, it doesn't prove development is economic without royalty when compared to the way the primary test defines ''economic-ness.'' Treat sunk costs the same in both tests and include them in the volume determination. Chance of relief is lost in a redetermination by defining all of the expended development costs as sunk	The difference in the way the two economic tests treat sunk costs favors the applicant. Omission of sunk costs from the dual test raises the net present value (NPV), improving chances for passing that part of the viability test. Their inclusion in the primary test has the opposite effect on NPV, again improving chances for passing that part of the viability test. As for volume determinations, the DWRRA directs us to consider sunk costs in determining eligibility for relief but not in setting a volume suspension to recover them. Finally, there is no difference in the treatment of sunk costs in the original application and redetermination. The only difference is in timing, i.e., more development costs may have been expended and hence treated as sunk at time of resubmission. That will raise the NPV in the dual test more than it will raise the NPV in the primary test, expanding the range of qualifying values.

COMMENTS ON DEEP WATER ROYALTY RELIEF (DWRR)—Continued

Requirement/Subject	Comment	MMS Response
203.70 & 91/Review and Evaluation—Post-production development report.	Full development cost is seldom known before first production, so a pre-production report would come before all wells would be drilled. Drilling costs are significant, often around 50 percent. Keep self-disclosure to encourage efficiency and reduce audit requirements but have an updated estimate of development costs provided before the first anniversary of start of production.	We agree that a review before production starts may be premature. The rules require the start-of-production cost report within 60 days after production begins. We may grant short extensions for extenuating circumstances. This gives applicants time to compile data on expenditures up to a well-defined point and avoids the ambiguity surrounding the actual start date and the need to estimate some cost items.
203.70, 76 & 90/Change in Material Fact—Start of Construction.	What constitutes start of construction or fabrication?	The revised rule stipulates the following requirements to verify when construction starts: (1) a copy of the contract with the fabrication yard, (2) a letter from the contractor certifying that construction has started on a specific system for a specific location, and (3) evidence of a payment of appropriate size based on current industry standards for the proposed development and production system.
203.71/Applying Suspension Volumes—Adding leases to a field.	Can a higher minimum suspension volume apply if the MMS evaluation of the application includes potential resources on unleased blocks and or leases not currently assigned to the field?	No. Minimum suspension volumes are based on the deepest lease assigned to the field up to the time the application is approved. Of course, we can still grant larger amounts of relief than the minimum suspension volumes, if we find them necessary to make the whole field economic.
203.73/Applying Suspension Volumes—Gas-to-Oil Conversion Factor.	The fixed conversion factor ignores fluctuations in the relative values of oil and gas and introduces bias as it overvalues gas relative to oil properties at current value ratios. The 8-to-1 ratio implied in the DWRRA may be better than the 5.62-to-1 ratio in the interim rule	The oil/gas ratio will continue to be based on the British thermal unit (Btu) conversion factor. Because the RSVP model values oil and gas separately, the conversion ratio affects only the size of the volume suspension, not qualification for relief. Qualified applicants already get minimum volumes under the DWRRA even if only small volume suspensions are needed. These minimum stipulated volumes were based on our studies using the Btu ratio. Hence, it would be inconsistent to have the volume suspension amounts based on relative prices when the minimum volumes were based on studies using the Btu ratio.
203.74/Redeterminations—Reprocessed Seismic Data.	Conditions for redeterminations should include reprocessed seismic data (using new algorithms). This differs from reinterpreting existing data, which is explicitly excluded as a basis for redetermination	We often can't distinguish a new algorithm from a reinterpretation of an old one, so we'll limit this requirement to new data developed by the applicant as a basis for a redetermination.
203.74/Redeterminations—Price Change Size.	A decline of 25 percent in oil or gas price is much too low to trigger a redetermination. Cash flow is very sensitive to price and a 10 percent drop in price can be enough to trigger a redetermination	Sharp price swings are often short-run phenomena not matched by changes in forecasts of long-term price trends used in a redetermination. Also price/cost differences, not just prices, drive cash flow. Some cost-cutting inevitably accompanies price declines. Only sustained, sizeable price declines, such as 25 percent, are likely to overwhelm cost-cutting opportunities enough to warrant a redetermination.
203.74/Redeterminations—Price Base.	What is the relevant price which must drop by 25 percent to qualify an applicant for a redetermination?	Applicants may seek a redetermination if a weighted 12-month moving average of daily closing New York Mercantile Exchange (NYMEX) prices for oil or gas has decreased by more than 25 percent since the most recent complete application. As the revised rule explains, the before and after prices are weighted using the volumes of oil and gas identified in the most likely scenario described in that application.
Deep Water Guidelines Supplementing 203.74/Redeterminations—Price Assumptions.	The minimum oil price of $16.30 per barrel and the average annual growth rate of 1.67 percent is too high for the next 25 years	Starting price assumptions are based on Energy Information Administration (EIA) historical data and growth rates in EIA's *Annual Energy Outlook* and will be updated regularly. To match the GOM market better, we'll use recent prices for Petroleum Administration for Defense District (PADD) III imports as a benchmark for starting prices. Adjustments for gravity differences are allowed. As with all projections, experience may prove starting prices representative or not and growth rates right or wrong. But applicants will be on an equal footing because we mandate specific parameters.
Deep Water Guidelines Supplementing 203.76/Changes in Material Fact—Limits.	The guidelines aren't consistent with the interim rule language and preamble discussion regarding ''material change.''	Agree. We have changed the guidelines to be consistent with the rule. In particular, the four circumstances (change of system, excess delay in starting, underspending on development, or false statements/omitted reports) used to signify a material change are the only ones—not just examples—of what justifies withdrawal of already granted relief.

COMMENTS ON DEEP WATER ROYALTY RELIEF (DWRR)—Continued

Requirement/Subject	Comment	MMS Response
203.76 & 87–89/Changes in Material Fact & Engineering, Production, and Cost reports—Multiple Development Scenarios.	MMS doesn't need three development scenarios to test viability because the section on withdrawing approval for royalty relief protects against significant changes	The withdrawal conditions focus on underspending development costs and changes in development systems evaluated in the application. They don't consider adjustments to planned capacity before or after production begins. We consider up to three scenarios to reflect uncertainty about final project size, timing, and production rates. We have clarified the options for simplifying the input data. Generally, whenever observed conditions or formal decisions foreclose some or all the uncertainty about particular variables, we accept fewer scenarios or point estimates for reservoirs, costs, and production.
203.76/Change in Material Fact—Reapplication with Sunk Development Costs.	Conversion of proposed development costs to sunk costs in a reapplication compounds the penalty from withdrawal. The reapplication is allowed less cost with which to justify relief	Agree. We'll allow applicants to renounce relief at any point after approval is granted and before production starts. When violation of a withdrawal condition is anticipated, giving up relief early can reduce the share of development costs that get considered as sunk costs in a subsequent application.
Deep Water Guidelines Supplementing 203.76 & 89/Change in Material Fact—Defining Development Cost.	What expenditures are included in development costs?	We'll count all eligible expenses planned for the most likely scenario between application and start of production. The spending threshold and any disallowed costs (for uneconomic reservoirs) will be specified in the relief approval. In assessing the economic viability of the subject field, we may remove the cash flows associated with uneconomic reservoirs.
Deep Water Guidelines Supplementing 203.76/ Change in Material Fact—Development Period.	What happens if the development period (i.e., time to first production) deviates from an applicant's proposal?	We'll compare actual to approved pre-production costs, regardless of how much or little time it takes to start production.
203.76/Only ''Significant'' Change in Material Fact before Withdrawal of Approved Relief.	Withdrawal as a result of actual cost below 80 percent (or 90 percent for redetermination that follows withdrawal of previously granted relief) of application estimates discourages capital efficiency. Also a 10 to 20 percent cost reduction may not greatly improve project economics. MMS should withdraw relief only if reduction in capital costs ''substantially'' improve project economics beyond those on which the project qualified. Even if such a change occurs, the applicant ought to be allowed to appeal to keep relief so as not to encourage inefficient expenditures	Withdrawal conditions need to be fixed and obvious, not flexible combinations to be determined later. We've taken three steps to soften the danger of a fixed threshold. First, the applicant may keep one-half of the relief if we're notified of the shortfall. Second, the withdrawal date is now after production begins. Third, the pre-production period is variable, so we count an applicant's costs over a flexible interval. As a result, it's unlikely that the company would substantially underspend its earlier capital cost projections by the time of review.
203.78/Applying Suspension Volumes—Price Ceilings on Different Products.	Will a market gas price increase that is not accompanied by a rise in oil price trigger a lifting of all the royalty-suspension volume for a field with mostly oil reserves or vice versa?	No. The statute doesn't explicitly answer this question. We've interpreted the applicable text to mean that price ceilings prescribed in the law for lifting relief should apply separately to each product for fields that produce both. Relief can be suspended on just the part of total production from a field whose price exceeded the threshold. Gas prices above $3.50 per million Btus (escalated to then-current dollars) won't lift relief on oil volumes if oil prices remain below $28 per barrel (escalated to then-current dollars) and vice versa. Escalation by the Gross Domestic Price deflator raises the thresholds each year.
203.78/Applying Suspension Volumes—Time Limits for Royalty Refunds or Credits.	A time limit should be set for MMS to make royalty refunds or credits, as are set for companies to repay back royalties with interest, under the price escalation clause	Agree. The new Royalty Simplification and Fairness Act requires that MMS process refunds or credits on production after September 1996 within 120 days of a lessee's request. Future rules will set forth procedures which deal with this request. The repayment period for companies is also set at 120 days.

COMMENTS ON THE REQUIRED REPORTS

Requirement/Subject	Comment	MMS Response
203.81/Independent Certification.	A certified public accountant (CPA) certification of historical expenditures reported in either the application or the pre-production report imposes unnecessary costs. Internal records and self certification are adequate	A CPA certification is an independent check and so might substitute for our audit. Besides, only eligible expenditures must be certified. However, to reduce the cost of the independent audit, we will accept a CPA opinion which identifies questionable elements or an unqualified opinion on the accuracy and relevance of the historical information presented.

COMMENTS ON THE REQUIRED REPORTS—Continued

Requirement/Subject	Comment	MMS Response
Deep Water Guidelines Supplementing 203.81/ Certification Format.	What is a CPA certification for sunk costs?	It's a CPA report that certifies your historical information is accurate and meets our stipulations on eligibility. As the revised guidelines state, an agent of the CPA firm must sign the certification and identify someone who knows the case and is authorized to respond to questions on it.
203.83/Administrative report—Certification of Non-Development.	Requiring certification that reserves won't be produced without relief is not enforceable and can be outdated as conditions change	Agree. We've eliminated this requirement. Considering sunk costs in the evaluation means that some fields that qualify for relief would be worth developing without relief.
203.85/Economic viability report—Inflation.	The spreadsheet model should allow for cost inflation	Future versions of the spreadsheet model may include a variable to account for cost-specific inflation or deflation. Technological progress could actually lower real costs over time despite general inflation of all prices and costs.
203.85/Economic viability report— Updating Price Assumptions Schedule.	MMS should fix a schedule for revising price assumptions (e.g., quarterly, annually). If MMS issues new assumptions while reviewing an application, they should clarify which assumptions apply (those at time of application or latest issued before the determination)	Agree. We'll publish updated price assumptions on the INTERNET annually, probably in the late spring when EIA's *Annual Energy Outlook* releases new data and forecasts. We'll use the price assumptions in place on the date of application submission.
203.85/Economic viability report—Revising Applicants' Assumptions-Discount Rates.	Will MMS accept the discount rate an applicant selects, or reserve the right to revise the discount rate?	We'll use the discount rate an applicant proposes in both the dual and primary tests, with no appropriateness review as long as it is within the range provided in the guidelines.
203.85/Economic viability report—Discount Rate Size.	The 10 percent discount rate is too low. Even 15 percent is too low because it risks rejected projects being abandoned	In all cases, the rates of return apply to a field with a discovery, so the risk of not finding oil or gas is gone. The range specified in the guidelines for the discount rate is based on recent historical experience, which in future years may assume a different trend. The industry's average after-tax, real rate of return, has been estimated to range from a high of 10.9 percent to a low of 1.4 percent between 1959 and 1988. (See A.T. Guernsey on behalf of Shell Oil Company, *Profitability Study: Crude Oil and Natural Gas Exploration, Development, and Production Activities in the USA, 1959–1988,* November 1990). Simulations with a version of our model found before-tax rates of return ranged from 1.2 to 4 percent higher than after-tax rates of return over various project conditions. Together, these estimates indicate that expecting before-tax discount rates, and hence rates of return, in the range of 10 to 15 percent are appropriate.
203.85/Economic viability report—Discount Rate Range.	Allowing variability in discount rates could lead to unequal treatment. Where applicants choose discount rates, the playing field isn't level. Instead, specify one for each of three water-depth thresholds and apply uniformly	The goal of a range of discount rates is to fit differences in companies' risk tolerance and opportunity cost. Applicants can tailor their risk preferences by water depth within this range if they choose to. We use probability methods that don't require a risk premium in the discount rate. However, a fixed discount rate across fields and companies within a water-depth category places all the burden for dealing with differences in risk on these probability distributions. We believe a better compromise is to give applicants the chance to use both factors to express their risks and uncertainties. Allowing companies to choose a rate for their projects is eminently fair, as long as they stay within our stipulated range and we use it in both economic viability tests.
203.89/Cost report—Sunk Costs Measurement.	The way MMS includes sunk costs doesn't recognize the time value of money, as past expenditures are carried forward without escalation. It's inappropriate to combine after-tax sunk costs with future costs and revenues expressed on a before-tax basis	The DWRRA directs us to consider all exploration, development, and production costs. Because the decision to proceed on a project is independent of sunk costs, the proper treatment of sunk costs for economic viability is to value them as zero. We balance these considerations by carefully defining expenses that constitute sunk costs, then we allow them as a deduction in the primary test and exclude them from the dual test. The after-tax part of sunk costs, like the before-tax size of prospective costs, is what the company still has to recover from the proposed project.
203.89/Sunk Costs—Scope	Sunk costs should include all reasonable post-lease acquisition costs (seismic data costs, overhead expenses, etc.). Extend the definition to include all project costs incurred by the lessee or on behalf of a lessee	We won't consider sunk costs incurred by previous owners of your lease or by third-parties. Also, we won't consider portions of sunk costs on your lease that you incurred prior to when you last bought into your lease. Further, if you have maintained continous ownership but changed the share of the lease you own, we count your sunk costs only in proportion to the share you owned when you incurred these costs. We do this because previous owners and third-parties already have been compensated through market transactions. Also, we do not believe we can really verify the relevance to current development of expenditures by third-parties or previous owners.

COMMENTS ON THE REQUIRED REPORTS—Continued

Requirement/Subject	Comment	MMS Response
203.91 & 76/Review and Evaluation—Post-production development report.	What must the post-production report contain? What happens if it isn't submitted?	The report must show and compare planned and actual pre-production costs. If you don't submit the report, you'll lose relief, just as you would for providing false historical or intentionally inaccurate information.

IV. Recovery of Costs

By Federal policy and law, we'll charge lessees applying for royalty relief under this rule an amount which recovers our cost of processing their applications. The Independent Office Appropriation Act (31 U.S.C. 9701) and OMB Circular A–25 require agencies to recover their costs when they provide services that confer special benefits or privileges to identifiable non-Federal recipients. Processing of applications for royalty relief clearly falls within this mandate. Furthermore, the Omnibus Appropriations Bill (Pub. L. 104–134, 110 Stat. 1321, April 26, 1996) authorizes collecting such fees.

We issued NTL No. 96–3N (signed June 21, 1996), which gives detailed amounts for processing royalty-relief applications and when and how applicants may pay us. Processing applications for royalty relief to increase production will cost $8,000. Complete applications under DWRR will cost either $16,000 to $34,000. Draft applications will cost either $10,500 to $28,500. For some applications, we may need to audit the financial data submitted to determine the proposed development's economics. That would cost up to $37,500. Ordinarily, no refund is given when we reject an application. However, if we reject a deep water application for incompleteness during the first 20 business days after receiving it, we'll refund all but $5,500 of the application fee. We'll revise the Notice to Lessees (NTL) periodically to reflect our cost experience and to provide other information helpful or necessary for administering this program.

Authors: Sam Fraser and Marshall Rose, Economics Division, prepared this document.

V. Administrative Matters

Executive Order (E.O.) 12866

This rule is significant due to novel policy issues arising from legal mandates, and OMB has reviewed this rule. We will make a copy of our determination of the effects of this rule available on request.

In summary, the DWRRA instructs us to grant royalty relief only in situations that are uneconomic at the lease-stipulated royalty rate. Hence, the economic effects can be estimated by the additional royalties that may be collected from fields that would otherwise not be developed until a later time, if at all. We estimated these effects by extrapolating to all known deep water fields the results of detailed analyses of 30 fields in the relevant water depths. MMS's field-based approach generates up to $45 million per year in additional royalty revenue, which is less than the threshold amount of $100 million annually.

The field-based approach provided in this final rule gives a single royalty-suspension volume for each qualifying field. The main alternative approach gives each individual lease or unit a separate royalty-suspension volume, subject to the minimum volumes specified in the DWRRA.

We chose the field-based approach because:

- The DWRRA's primary author stated that he intended the DWRRA to encourage production from new fields without providing any more relief than needed;
- The field-based approach provides a substantial incentive for developing marginal fields in deep water while still ensuring a fair return to the Treasury;
- The minimum suspension volumes specified in the DWRRA were derived from an analysis of fields, not individual leases; and
- This rule needs to be consistent with the rules for royalty suspensions on deep water tracts leased after November 28, 1995, in the same parts of the GOM so that all deep water leases on the OCS receive equitable treatment.

Regulatory Flexibility Act

This rule can have a positive economic effect on some small entities. A copy of our analysis of this impact is available on request.

In summary, this rule sets the terms and conditions for granting royalty relief under the provisions of section 8(a)(3)(A) of the OCSLA. These terms reduce costs for end-of-life operations by 6 to 10 percent, more than doubling profits. That should significantly prolong operations on marginally economic leases. We can't estimate the number of leases that may be affected from past experience, because the terms have been changed from those previously available to marginal OCS leases. We estimate that small entity operators account for under 10 percent of production from OCS leases.

This rule also sets terms and conditions for granting royalty-suspension volumes under the DWRRA for certain deep water leases on the OCS in the GOM. These leases were issued as a result of a lease sale held before November 28, 1995. The conditions limit these terms to the rare situations in which royalty costs are the difference between unprofitable and profitable development. One of two applications for deep water relief received under the interim version of this rule was from a small entity.

Paperwork Reduction Act

In connection with the interim final rulemaking (IFR) process, we submitted the information collection requirements in 30 CFR 203 to OMB and conducted a full review and comment process for this collection of information. OMB approved the information collection (OMB No. 1010–0071) on October 7, 1996, to expire on October 31, 1999.

Earlier in the preamble we discussed comments received on the information collection aspects of the IFR. Based on experience and the changes made in this rule, we will submit a revised information collection package to OMB for approval 60 days after this rule is published. With this rule, we are starting the 60-day comment period. The Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The information collection aspects of this final rule will not take effect until approved by OMB.

We invite the public and other Federal agencies to comment on the collection of information as discussed below. Send comments regarding any aspect of the collection to the Minerals Management Service, Attention: Rules Processing Team, 381 Elden Street, Mail Stop 4020, Herndon, VA 20170. Your comments should be received by March 17, 1998.

We use the information to determine whether royalty relief will result in production that wouldn't otherwise occur. We rely largely on your information to make these determinations. Your application for royalty relief must contain enough information on finances, economics, reservoirs, G&G characteristics, production, and engineering estimates for us to determine whether: (1) We should grant relief under the law, and (2) the requested relief will ultimately recover more resources and return a reasonable profit on project investments. Your fabricator confirmation and post-production development reports must contain enough information for us to verify that your application reasonably represented your plans.

Applicants (respondents) are Federal OCS oil and gas lessees. Applications are required to obtain or retain a benefit. Therefore, if you apply for royalty relief, you must provide this information. We will protect information considered proprietary under applicable law and under regulations at § 203.63(b) and part 250 of this chapter.

We estimate the annual public reporting burden for this information collection will average approximately 14,700 hours, not the 38,730 hours originally estimated for the interim final rule. The reduction is due primarily to an adjustment in re-estimating the number of applications we expect to receive. We also made minor program reductions in the estimate based on the changes in the final rule. The average burden per response is estimated at 335 burden hours. This includes the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. A breakdown of the estimated burden is included in the supporting statement we submitted to OMB for this collection of information. You may obtain a copy of that supporting statement from MMS's Information Collection Clearance Officer (202/208–7744). In calculating the burdens, we've assumed that respondents perform some of the requirements and maintain records in the normal course of their activities. We consider these to be usual and customary. You are invited to provide information in your comments if you disagree with this assumption.

We specifically solicit comments on the following questions:

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

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

(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 the applicants, including the use of appropriate automated electronic, mechanical, or other forms of information technology?

In addition, the Paperwork Reduction Act requires us to estimate the total annual cost burden to respondents or recordkeepers resulting from the collection of information. We need your comments to identify any reporting and recordkeeping cost burdens other than those discussed above. Your response should split the cost estimate into two components: (a) Total capital and startup cost component; and (b) annual operation, maintenance, and purchase of services component. Your estimates should consider the costs to generate, maintain, and disclose or provide the information. You should describe the methods you use to estimate major cost factors, including system and technology acquisition, expected useful life of capital equipment, discount rate(s), and the period over which you incur costs. Capital and startup costs include, among other items, computers and software you purchase to prepare for collecting information; monitoring, sampling, drilling, and testing equipment; and record storage facilities. Generally, your estimates should not include equipment or services purchased: (i) before October 1, 1995; (ii) to comply with requirements not associated with the information collection; (iii) for reasons other than to provide information or keep records for the Government; or (iv) as part of customary and usual business or private practices.

Takings Implication Assessment

DOI certifies that this rule does not represent a governmental action that can interfere with constitutionally protected property rights. Therefore, we don't need to do a Takings Implication Assessment under E.O. 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

E.O. 12988

DOI has certified to OMB that the rule meets the applicable reform standards provided in sections 3(a) and 3(b)(2) of E.O. 12988.

National Environmental Policy Act

DOI has determined that this rule isn't a major Federal action that significantly affects the quality of the human environment, so we don't need an Environmental Impact Statement.

Unfunded Mandates Reform Act of 1995

DOI has determined and certifies according to the Unfunded Mandates Reform Act, 2 U.S.C. 1502 *et seq.*, that this rule will not impose a cost of $100 million or more in any given year on State, local, and tribal governments or the private sector.

''Plain English'' Style of Writing

We've written this regulation in the form of questions in the first person (I) and answers in the second person (you) because readers may find it simpler to read and understand. A question and its answer combine to establish a rule. The applicant and the agency must follow the language in the question and its answer.

List of Subjects in 30 CFR Part 203

Continental shelf, Government contracts, Indians-lands, Minerals Royalties, Oil and gas exploration, Public lands-mineral resources, Sulphur.

Dated: November 6, 1997.

Bob Armstrong,

Assistant Secretary, Land and Minerals Management.

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

PART 203—RELIEF OR REDUCTION IN ROYALTY RATES

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

Authority: 25 U.S.C. 396 *et seq.*; 25 U.S.C. 396a *et seq.*; 25 U.S.C. 2101 *et seq.*; 30 U.S.C. 181 *et seq.*; 30 U.S.C. 351 *et seq.*; 30 U.S.C. 1001 *et seq.*; 30 U.S.C. 1701 *et seq.*; 31 U.S.C. 9701 *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. Subpart A is revised to read as follows:

Subpart A—General Provisions

Sec.
203.0 What definitions apply to this part?
203.1 What is MMS's authority to grant royalty relief?
203.2 When can I get royalty relief?
203.3 Why must I pay a fee to request royalty relief?
203.4 How do the provisions in this part apply to different types of leases and projects?

Subpart A—General Requirements

§ 203.0 What definitions apply to this part?

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

Complete application means an original and two copies of the six reports consisting of the data specified in 30 CFR 203.81, 203.83 and 203.85 through 203.89, along with one set of digital information, which MMS has reviewed and found complete.

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

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

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

Expansion project 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 increase the ultimate recovery of resources from a pre-Act lease and that involves 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 construction has begun, and a receipt for the customary down payment.

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

Lease means a lease or unit.

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 involving a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well project, etc.) on a current pre-Act lease under a Development Operations Coordination Document—or its supplement—approved by the Secretary of the Interior after November, 28, 1995.

Nonbinding assessment means an opinion by MMS of whether your field could qualify for royalty relief. It is based on your draft application and does not entitle the field to relief.

Performance conditions means minimum conditions you must meet, after we have granted relief and before production begins, to remain qualified for that relief. If you do not meet each one of these performance conditions, we consider it a change in material fact significant enough to invalidate our original evaluation and approval.

Pre-Act lease means a lease issued as a result of a lease sale held before November 28, 1995; in a water depth of at least 200 meters; and in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude.

Production means all oil, gas, and other relevant products you save, remove, or sell from a tract or those quantities allocated to your tract under a unitization formula, as measured for the purposes of determining the amount of royalty payable to the United States.

Project means any activity that requires at least a permit to drill.

Redetermination means your request for us to reconsider our determination on royalty relief if we have rejected your application or if we have granted relief but you want a larger suspension volume.

Renounce means action you take to give up relief after we have granted it and before you start production.

Sunk costs means costs (as specified in 30 CFR 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 include the costs of the discovery well qualified as producible under 30 CFR part 250, subpart A but do not include any pre-discovery activity costs or lease acquisition and holding costs such as cash bonus and rental payments.

Withdraw means action we take on a field that has qualified for relief if you have not met one or more of the performance conditions.

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

The Outer Continental Shelf (OCS) Lands Act, 43 U.S.C. 1337, as amended by the OCS Deep Water Royalty Relief Act (DWRRA), Public Law 104–58, authorizes us to grant royalty relief in three situations.

(a) Under 43 U.S.C. 1337(a)(3)(A), we may reduce or eliminate any royalty or a net profit share specified for an OCS lease to promote increased production.

(b) Under 43 U.S.C. 1337(a)(3)(B), we may reduce, modify, or eliminate any royalty or net profit share to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. This authority is restricted to leases in the Gulf of Mexico (GOM) that are west of 87 degrees, 30 minutes West longitude.

(c) Under 43 U.S.C. 1337(a)(3)(C), we may suspend royalties for designated volumes of new production from any lease if:

(1) Your lease is in deep water (water at least 200 meters deep);

(2) Your lease is in designated areas of the GOM (west of 87 degrees, 30 minutes West longitude);

(3) Your lease was acquired in a lease sale held before the DWRRA (before November 28, 1995);

(4) We find that your new production would not be economic without royalty relief; and

(5) Your lease is on a field that did not produce before enactment of the DWRRA, or if you propose a project to significantly expand production under a Development Operations Coordination Document (DOCD) or a supplementary DOCD, that MMS approved after November 28, 1995.

§ 203.2 When can I get royalty relief?

We can reduce or suspend royalties for OCS leases or projects that meet the criteria in the following table.

IF YOU HAVE A LEASE—	AND IF YOU—	THEN YOU MAY BE GRANTED—
That generates earnings which cannot sustain production (*End-of-Life lease*),.	Seek to increase production by operating the lease beyond the point at which it is economic under the existing royalty rate,.	A reduced royalty rate on current production flows along with a higher royalty rate on some additional production flows.
In designated areas of the deep water GOM, acquired in a lease sale held before November 28, 1995, and you propose activity in a DOCD or supplement to significantly expand production,.	Are producing and seek to increase ultimate recovery of resources from the field with a substantial investment (e.g., platform, multiple wells, subsea template) (an *expansion project*),.	A royalty suspension for an increment to production large enough to make the project economic.
In designated areas of the deep water GOM, acquired in a lease sale held before November 28, 1995 (*pre-Act lease*),.	Are on a field from which no current pre-Act lease produced (other than test production) before November 28, 1995 (*authorized field*),.	A royalty suspension for a minimum production volume plus any additional volume needed to make the field economic.

§ 203.3 Why must I pay a fee to request royalty relief?

(a) When you submit an application or ask for a preview assessment, you must include a fee to reimburse us for our costs of processing your application or assessment. Federal policy and law require us to recover the cost of services that confer special benefits to identifiable non-Federal recipients. The Independent Offices Appropriation Act (31 U.S.C. 9701), Office of Management and Budget Circular A–25, and the Omnibus Appropriations Bill (Pub. L. 104–133, 110 Stat. 1321, April 26, 1996) authorize us to collect these fees.

(b) We will specify the necessary fees for each of the types of royalty-relief applications and possible MMS audits in a Notice to Lessees. We will periodically update the fees to reflect changes in costs as well as provide other information necessary to administer royalty relief.

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

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

(a) Provisions relating to application content in §§ 203.51, 203.62 and 203.81 through 203.89.

Information elements	End-of-life lease	Deep water expansion project	Pre-act deep water lease
Administrative information report	x	x	x
Net revenue and relief justification report (prescribed format)	x		
Economic viability and relief justification report (Royalty Suspension Viability Program (RSVP) model inputs justified with Geological & Geophysical (G&G), Engineering, Production, & Cost reports)		x	x
G&G report		x	x
Engineering report		x	x
Production report		x	x
Deep Water cost report		x	x

(b) Provisions relating to verification in §§ 203.70, 203.81 and 203.90 through 203.91.

Confirmation elements	End-of-life lease	Deep water expansion project	Pre-act deep water lease
Fabricator's confirmation report		x	x
Post-production development report (approved by certified public accountant (CPA)		x	x

(c) Provisions relating to approval criteria contained in §§ 203.50, 203.52, 203.60 and 203.67.

Approval conditions	End-of-life lease	Deep water expansion project	Pre-act deep water lease
At least 12 of the last 15 months have the required level of production	x		
Already producing	x	x	
Well can produce			x
Royalties for qualifying months exceed 75 percent of net revenue (NR)	x		
Substantial investment (e.g., platform, multiple wells, subsea template)		x	
Determined to be economic only with relief		x	x

(d) Provisions related to redetermination in §§ 203.52 and 203.74 through 203.75.

Redetermination conditions	End-of-life lease	Deep water expansion project	Pre-act deep water lease
After 12 months under current rate, criteria same as for approval	x		
For material change in geologic data, prices, or costs		x	x

(e) Provisions related to the format of relief in §§ 203.53 and 203.69.

Relief rate & volume	End-of-life lease	Deep water expansion project	Pre-act deep water lease
One-half pre-application effective lease rate on the qualifying amount, 1.5 times pre-application effective lease rate on additional production up to twice the qualifying amount, and the pre-application effective lease rate for any larger volumes	x		
Qualifying amount is the average monthly production for 12 qualifying months	x		
Zero royalty rate on the suspension volume and the original lease rate on additional production		x	x
Field Suspension volume is at least 17.5, 52.5 or 87.5 million barrels of oil equivalent (MMBOE)			x
Amount needed to become economic		x	x

(f) Provisions related to discontinuing relief §§ 203.54 and 203.78.

Full royalty resumes when—	End-of-life lease	Deep water expansion project	Pre-act deep water lease
Average NYMEX price for last 12 months is at least 25 percent above the average for the qualifying months	x		
Average NYMEX price for last 12 months exceeds $28/bbl or $3.50/mcf, escalated by the gross domestic product deflator since 1994		x	x

(g) Provisions related to the end, loss or reduction of relief in §§ 203.55 and 203.76.

Relief withdrawn or reduced	End-of-life lease	Deep water expansion project	Pre-act deep water lease
Recipient so requests	x		
Lease rate is at the effective rate for 12 consecutive months	x		
Conditions that we may specify in the approval letter in individual cases actually occur	x		
Not submitting post-production report that compares expected to actual costs		x	x
Change of development system		x	x
Excess delay in starting fabrication		x	x
Spending less than 80 percent of proposed pre-production costs but notifying us in post-production report		x	x
Amount of relief volume is produced		x	x

3. Subpart B is revised to read as follows:

Subpart B—OCS Oil, Gas, and Sulfur General

Royalty Relief for end-of-life Leases

Sec.
203.50 Who may apply for end-of-life royalty relief?
203.51 How do I apply for end-of-life royalty relief?
203.52 What criteria must I meet to get relief?
203.53 What relief will MMS grant?
203.54 How does my relief arrangement for an oil and gas lease operate if prices rise sharply?
203.55 Under what conditions can my end-of-life royalty relief arrangement for an oil and gas lease be ended?
203.56 Does relief transfer when a lease is assigned?

Royalty Relief For Deep Water Expansion Projects And Pre-Act Deep Water Leases

203.60 Who may apply for deep water royalty relief?
203.61 How do I assess my chances for getting relief?
203.62 How do I apply for relief?
203.63 Does my application have to include all leases in the field?
203.64 How many applications may I file on a field?
203.65 How long will MMS take to evaluate my application?
203.66 What happens if MMS does not act in the time allowed under § 203.65, including any extensions?
203.67 What economic criteria must I meet to get royalty relief on an authorized field or expansion project?
203.68 What pre-application costs will MMS consider in determining economic viability?
203.69 If my application is approved, what royalty relief will I receive?
203.70 What information must I provide after MMS approves relief?
203.71 How does MMS allocate a field's suspension volume between my lease and other leases on my field?
203.72 Can my lease receive more than one suspension volume?
203.73 How do suspension volumes apply to natural gas?
203.74 When will MMS reconsider its determination?
203.75 What risk do I run if I request a redetermination?
203.76 When might MMS withdraw or reduce the approved size of my relief?
203.77 May I voluntarily give up relief if conditions change?
203.78 Do I keep relief if prices rise significantly?
203.79 How do I appeal MMS's decisions related to Deep Water Royalty Relief?

Required Reports

203.81 What supplemental reports do royalty-relief applications require?

203.82 What is MMS's authority to collect this information?
203.83 What is in an administrative information report?
203.84 What is in a net revenue and relief justification report?
203.85 What is in an economic viability and relief justification report?
203.86 What is in a G&G report?
203.87 What is in an engineering report?
203.88 What is in a production report?
203.89 What is in a deep water cost report?
203.90 What is in a fabricator's confirmation report?
203.91 What is in a post-production development report?

Subpart B–OLS Oil, Gas, and Sulfur General

Royalty Relief for End–of–life Leases

§ 203.50 Who may apply for end-of-life royalty relief?

You may apply for royalty relief in two situations.

(a) Your end-of-life lease (as defined in § 203.2) is an oil and gas lease and has average daily production of at least 100 barrels of oil equivalent (BOE) per month (as calculated in § 203.73) in at least 12 of the past 15 months. The most recent of these 12 months are considered the qualifying months.

(b) Your end-of-life lease is other than an oil and gas lease (e.g., sulphur) and has production in at least 12 of the past 15 months. The most recent of these 12 months are considered the qualifying months.

§ 203.51 How do I apply for end-of-life royalty relief?

You must submit a complete application and the required fee to the appropriate MMS Regional Director. Your MMS regional office will provide specific guidance on the report formats. A complete application for relief includes:

(a) An administrative information report (specified in § 203.83) and

(b) A net revenue and relief justification report (specified in § 203.84).

§ 203.52 What criteria must I meet to get relief?

(a) To qualify for relief, you must demonstrate that the sum of royalty payments over the 12 qualifying months exceeds 75 percent of the sum of net revenues (before-royalty revenues minus allowable costs, as defined in § 203.84).

(b) To re-qualify for relief, e.g., either applying for additional relief on top of relief already granted, or applying for relief sometime after your earlier agreement terminated, you must demonstrate that:

(1) You have met the criterion listed in paragraph (a) of this section, and

(2) The 12 required qualifying months of operation have occurred under the current royalty arrangement.

§ 203.53 What relief will MMS grant?

(a) If we approve your application and you meet certain conditions, we will reduce the pre-application effective royalty rate by one-half on production up to the relief volume amount. If you produce more than the relief volume amount:

(1) We will impose a royalty rate equal to 1.5 times the effective royalty rate on your additional production up to twice the relief volume amount; and

(2) We will impose a royalty rate equal to the effective rate on all production greater than twice the relief volume amount.

(b) Regardless of the level of production or prices (see § 203.54), royalty payments due under end-of-life relief will not exceed the royalty obligations that would have been due at the effective royalty rate.

(1) The effective royalty rate is the average lease rate paid on production during the 12 qualifying months.

(2) The relief volume amount is the average monthly BOE production for the 12 qualifying months.

§ 203.54 How does my relief arrangement for an oil and gas lease operate if prices rise sharply?

In those months when your current reference price rises by at least 25 percent above your base reference price, you must pay the effective royalty rate on all monthly production.

(a) 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;

(b) Your base reference price is a weighted average of daily closing prices on the NYMEX for light sweet crude oil and natural gas during the qualifying months; and

(c) Your weighting factors are the proportions of your total production volume (in BOE) provided by oil and gas during the qualifying months.

§ 203.55 Under what conditions can my end-of-life royalty relief arrangement for an oil and gas lease be ended?

(a) If you have an end-of-life royalty relief arrangement, you may renounce it at any time. The lease rate will return to the effective rate during the qualifying period in the first full month following our receipt of your renouncement of the relief arrangement.

(b) If you pay the effective lease rate for 12 consecutive months, we will terminate your relief. The lease rate will return to the effective rate in the first full month following this termination.

(c) We may stipulate in the letter of approval for individual cases certain events that would cause us to terminate relief because they are inconsistent with an end-of-life situation.

§ 203.56 Does relief transfer when a lease is assigned?

Yes. Royalty relief is based on the lease circumstances, not ownership. It transfers upon lease assignment.

Royalty Relief For Deep Water Expansion Projects And Pre-Act Deep Water Leases

§ 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 hold a pre-Act lease on an authorized field (as defined in § 203.0) or you propose an expansion project (as defined in § 203.0).

§ 203.61 How do I assess my chances for getting relief?

You may ask for a nonbinding assessment (a formal opinion on whether a field would qualify for royalty relief) before turning in your first complete application on an authorized field. This field must have a qualifying well under 30 CFR part 250, subpart A, or be on a lease that has allocated production under an approved unit agreement.

(a) To request a nonbinding assessment, you must:

(1) Submit a draft application in the format and detail specified in guidance from the MMS regional office for the GOM;

(2) Propose to drill at least one more appraisal well if you get a favorable assessment; and

(3) Pay a fee under § 203.3.

(b) You must wait at least 90 days after receiving our assessment to apply for relief under § 203.62.

(c) This assessment is not binding because a complete application may contain more accurate information that does not support our original assessment. It will help you decide whether your proposed inputs for evaluating economic viability and your supporting data and assumptions are adequate.

§ 203.62 How do I apply for relief?

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

(a) Your application for deep water royalty relief must include an original and two copies (one set of digital information) of:

(1) Administrative information report;

(2) Deep water economic viability and relief justification report;

(3) G&G report;

(4) Engineering report;

(5) Production report; and

(6) Deep water cost report.

(b) Section 203.82 explains why we are authorized to require these reports.

(c) Sections 203.81, 203.83, and 203.85 through 203.89 describe what these reports must include. The MMS GOM Regional Office will guide you on the format for the required reports.

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

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 (c) of this section and § 203.64.

(a) The Regional Director maintains a Field Names Master List with updates of all leases in each designated field.

(b) To avoid sharing proprietary data with other lessees on the field, you may submit your proprietary G&G report separately from the rest of your application. Your application is not complete until we receive all the required information for each lease on the field. We will not disclose proprietary data when explaining our assumptions and reasons for our determinations under § 203.67.

(c) We will not require a joint application if you show good cause and honest effort to get all lessees in the field to participate. If you must exclude a lease from your application because its lessee will not participate, that lease is ineligible for the royalty relief for the designated field.

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

You may file one complete application for royalty relief during the life of the field. However, you may send another application if:

(a) You are eligible to apply for a redetermination under § 203.74;

(b) You apply for royalty relief for an expansion project;

(c) You withdraw the application before we make a determination; or

(d) You apply for end-of-life royalty relief.

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

(a) We will determine within 20 working days if your application for royalty relief is complete. If your application is incomplete, we will explain in writing what it needs. If you withdraw a complete application, you may reapply.

(b) We will evaluate your first application on a field within 180 days and a redetermination under § 203.75 within 120 days after we say it is complete.

(c) We may ask to extend the review period for your application under the conditions in the following table.

If—	Then we may—
We need more records to audit sunk costs	Ask to extend the 120-day or 180-day evaluation period. The extension we request will equal the number of days between when you receive our request for records and the day we receive the records.
We cannot evaluate your application for a valid reason, such as missing vital information or inconsistent or inconclusive supporting data.	Add another 30 days. We may add more than 30 days, but only if you agree.
We need more data, explanations, or revision	Ask to extend the 120-day or 180-day evaluation period. The extension we request will equal the number of days between when you receive our request and the day we receive the information.

(d) We may change your assumptions under § 203.62 if our technical evaluation reveals others that are more appropriate. We may consult with you before a final decision and will explain any changes.

(e) We will notify all designated lease operators within a field when royalty relief is granted.

§ 203.66 What happens if MMS does not act in the time allowed under § 203.65, including any extensions?

If we do not act within the timeframes established in § 203.65, the conditions in the following table apply.

If you apply for royalty relief for—	And we do not decide within the time specified—	As long as you—
An authorized field	You get the minimum suspension volumes specified in § 203.69	Abide by §§ 203.70 & 76
An expansion project	You get a royalty suspension for the first year of production	Abide by §§ 203.70 & 76

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

Your field or project must require royalty relief to be economic and must become economic with this relief. That is, we will not approve applications if we determine that royalty relief cannot make the field or project economically viable.

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

(a) We will not consider ineligible costs as set forth in § 203.89(h) in determining economic viability for purposes of royalty relief.

(b) We will consider sunk costs (allowable expenditures on and after the discovery well as specified in § 203.89(a)) in accordance with the following table.

We will—	When—
Include sunk costs	The field has not produced, other than test production, before the application submission date.
Not include sunk costs	Determining whether an authorized field can become economic with any relief (see § 203.67).
Not include sunk costs	Determining how much suspension volume is necessary to make development economic (see § 203.69(c)).
Not include sunk costs	Evaluating an expansion project.

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

This section applies only to leases on which you have applied for and received a royalty-suspension volume under section 302 of the DWRRA. We will not collect royalties on a specified suspension volume for your field. Suspension amounts include volumes allocated to a lease under an approved unit agreement and exclude any volumes that do not bear a royalty under the lease or the regulations of this chapter.

(a) For authorized fields, the minimum royalty-suspension volumes are:

(1) 17.5 million barrels of oil equivalent (MMBOE) for fields in 200 to 400 meters of water;

(2) 52.5 MMBOE for fields in 400 to 800 meters of water; and

(3) 87.5 MMBOE for fields in more than 800 meters of water.

(b) If the application for the field includes leases in different categories of water depth, we apply the minimum royalty-suspension volume for the deepest lease then associated with 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 approved. These publications are available from the GOM Regional Office.

(c) You will get a royalty-suspension volume above the minimum if we determine that you need more to make developing the field economic.

(d) For expansion projects, the minimum suspension volumes do not apply. If we determine that your expansion project may be economic only with relief, we will determine and grant you the royalty-suspension volume necessary to make the project economic.

(e) A royalty-suspension volume 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 expansion project that are entitled to share the royalty suspension volume.

§ 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 and 203.90 through 203.91 describe what these reports must include. MMS's GOM Regional Office will tell you the formats.

Required report	When due to MMS	Due date extensions
Fabricator's confirmation report.	Within 1 year after approval of relief	MMS Director may grant you an extension under § 203.79(c) for up to 1 year.
Post-production report	Within 60 days after the start of production that is subject to the approved royalty-suspension volume.	With acceptable justification from you, MMS's GOM Regional Director may extend due date up to 60 days.

§ 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 the lease is assigned to the field, and whether we award the volume suspension by an approved application or establish it in the lease terms.

(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 as appropriate:

If—	Then—	And—
We assign an eligible lease to your field after we approve or establish relief.	We will not change your field's royalty-suspension volume.	The newly assigned leases may share in any remaining royalty relief.
We assign a pre-Act lease to your field after you submit a complete application.	We will not change your field's royalty-suspension volume.	The newly assigned leases may share in any remaining royalty relief by filing the short form application specified in § 203.83 and authorized in § 203.82.
We assigned a pre-Act lease to your field before you submitted the royalty relief application.	We will not change your field's royalty-suspension volume.	The newly assigned lease will not share in the relief if it did not participate in the application.
We reassign a well on a pre-Act lease to another field.	The past production from that well counts toward the royalty suspension volume of the field to which the well is reassigned.	The past production from that well will not count toward any royalty suspension volume granted to the field from which it was reassigned.

(b) If your authorized field has an automatic royalty-suspension volume established under § 260.110 of this chapter, we will suspend payment of royalties on production from all eligible leases in the field until their cumulative production equals the automatic volume. The following conditions also apply as appropriate:

If—	Then—	And—
Another eligible lease is assigned to your field	Your field's royalty-suspension volume does not change.	The newly assigned lease may share in relief only to the extent that cumulative production from your field is less than the automatic volume.
A pre-Act lease applies (along with the other leases in the field) and qualifies (subject to the field's automatic suspension volume) for royalty relief under §§ 203.67 and 203.69.	Your field's royalty-suspension volume may increase or stay the same.	All leases in the field share the one, higher royalty-suspension volume if we approve the application; *or* The eligible leases in the field keep the automatic volume if we reject the application.

(c) If you have an expansion project with more than one lease, the royalty-suspension volume for each lease equals that lease's actual incremental production from the project (or production allocated under an approved unit agreement) until cumulative incremental production for all leases in the project equals the project's approved royalty-suspension volume.

(d) You may receive a royalty-suspension volume only if your entire lease is west of 87 degrees, 30 minutes West longitude. If the field lies on both sides of this meridian, only leases located entirely west of the meridian will receive a royalty-suspension volume.

§ 203.72 Can my lease receive more than one suspension volume?

Yes. You may apply for royalty relief that involves more than one suspension volume under § 203.62 in two circumstances.

(a) Each field that includes your lease may receive a separate royalty-suspension volume, if it meets the evaluation criteria of § 203.67.

(b) An expansion project on your lease may receive a separate royalty-suspension volume, even if we have already granted a royalty-suspension volume to the field that encompasses the project. But the reserves associated with the project must not have been part of our original determination, and the project must meet the evaluation criteria of § 203.67.

§ 203.73 How do suspension volumes apply to natural gas?

You must measure natural gas production under the royalty-suspension volume as follows: 5.62 thousand cubic feet of natural gas, measured in accordance with 30 CFR part 250, subpart L, equals one barrel of oil equivalent.

§ 203.74 When will MMS reconsider its determination?

Under certain conditions, you may request a redetermination if we deny your application, if you want your approved royalty-suspension volume to change, after we withdraw approval, or after you renounce royalty relief. To be eligible for a redetermination, at least one of the following three conditions must occur.

(a) You have significant new G&G data and you previously have not either requested a redetermination or reapplied for relief after we withdrew approval or you relinquished royalty relief. ''Significant'' means that the new G&G data:

(1) Results from drilling new wells or getting new three-dimensional seismic data and information (but not reinterpreting old data);

(2) Did not exist at the time of the earlier application; and

(3) Changes your estimates of gross resource size, quality, or projected flow rates enough to materially affect the results of our earlier determination.

(b) Your current reference price decreases by more than 25 percent from your base reference price. For royalty relief on deep water expansion projects and pre-Act deep water leases:

(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 this royalty relief.

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

§ 203.75 What risk do I run if I request a redetermination?

If you request a redetermination after we have granted you a suspension volume, you could lose some or all of the previously granted relief. This can happen because you must file a new complete application and pay the required fee, as discussed in § 203.62. We will evaluate your application under § 203.67 using the conditions prevailing at the time of your redetermination request. In our evaluation, we may find that you should receive a larger, equivalent, smaller, or no suspension volume. This means we could find that you do not qualify for the amount of relief previously granted or for any relief at all.

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

We will withdraw approval of relief for any of the following reasons.

(a) You change the type of development system proposed in your application (e.g., change from a fixed platform to floating production system, tension leg platform to a moored catenary system such as a SPAR platform, 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 1 year of the date we approved your application—unless the MMS Director grants you an extension under § 203.79(c).

(c) You do not tell us in your post-production development report (§ 203.70), and we find out your actual development costs are less than 80 percent of the eligible development costs estimated in your application's most likely scenario. Development costs are those incurred between the application submission date and start of production. If you tell us about this result in the post-production development report, you may retain 50 percent of the original royalty-suspension volume.

(d) We granted you a royalty-suspension volume after you qualified for a redetermination under § 203.74(c), and we find out your actual development costs are less than 90 percent of the eligible development costs associated with your application's most likely scenario. Development costs are those expenditures defined in § 203.89(b) incurred between your application submission date and start of production.

(e) You do not send us the fabrication confirmation report or the post-production development report, or you provide false or intentionally inaccurate information that was material to our granting royalty relief under this section. You must pay royalties and late-payment interest determined under 30 U.S.C. 1721 and § 218.54 of this chapter on all volumes for which you used the royalty suspension. You also may be subject to penalties under other provisions of law.

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

You may renounce approved royalty-suspension volumes as soon as you anticipate violating one of the withdrawal conditions, or for any other reason, before you start production.

§ 203.78 Do I keep relief if prices rise significantly?

No, you must pay full royalties if prices rise above the statutory base price for light sweet crude oil or natural gas.

(a) Suppose the arithmetic average of the daily closing NYMEX light sweet crude oil prices for the previous calendar year exceeds $28.00 per barrel, as adjusted in paragraph (f) of this section. In this case, we retract the royalty relief authorized in this section and you must:

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

(2) Pay royalties on all your oil production in the current year.

(b) Suppose the arithmetic average of the daily closing NYMEX natural gas prices for the previous calendar year exceeds $3.50 per million British thermal units (Btu), as adjusted in paragraph (f) of this section. In this case, we retract the royalty relief authorized in this section and you must:

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

(2) Pay royalties on all your natural gas production in the current year.

(c) Production under both paragraphs (a) and (b) of this section counts as part of the royalty-suspension volume.

(d) You are entitled to a refund or credit, with interest, of royalties paid on any production (that counts as part of the royalty-suspension volume):

(1) Of oil if the arithmetic average of the closing oil prices for the current calendar year is $28.00 per barrel or less, as adjusted in paragraph (f) of this section, and

(2) Of gas if the arithmetic average of the closing natural gas prices for the current calendar year is $3.50 per million Btu or less, as adjusted in paragraph (f) of this section.

(e) You must follow our regulations in part 230 of this chapter for receiving refunds or credits.

(f) We change the prices referred to in paragraphs (a), (b) and (d) of this section during each calendar year after 1994. These prices change by the percentage the implicit price deflator for the gross domestic product changed during the preceding calendar year.

§ 203.79 How do I appeal MMS's decisions related to Deep Water Royalty Relief?

(a) Once we have designated your lease as part of a field and notified you and other affected operators of the designation, you can request reconsideration by sending the MMS Director a letter within 15 days that also states your reasons. The MMS Director's response is the final agency action.

(b) Our decisions on your application for relief from paying royalty under § 203.67 and the royalty-suspension volumes under § 203.69 are final agency actions.

(c) If you cannot start construction by the deadline in § 203.76(b) for reasons beyond your control (e.g., strike at the fabrication yard), you may request an extension up to 1 year by writing the MMS Director and stating your reasons. The MMS Director's response is the final agency action.

(d) We will notify you of all final agency actions by certified mail, return receipt requested. Final agency actions are not subject to appeal to the Interior Board of Land Appeals under 30 CFR part 290 and 43 CFR part 4. They are judicially reviewable under section 10(a) of the Administrative Procedure Act (5 U.S.C. 702) *only* if you file an action within 30 days of the date you receive our decision.

Required Reports

§ 203.81 What supplemental reports do royalty-relief applications require?

(a) You must send us the supplemental reports listed below 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 deep water lease
Administrative information report	x	x	x
Net revenue & relief justification report	x	....	....
Economic viability & relief justification report (RSVP model inputs justified by other required reports)	....	x	x
G&G report	....	x	x
Engineering report	....	x	x
Production report	....	x	x
Deep water cost report	....	x	x
Fabricator's confirmation report	....	x	x
Post-production development report	....	x	x

(b) You must certify that all information in your application, fabricator's confirmation and post-production development reports is accurate, complete, and conforms to the most recent content and presentation guidelines available from the MMS GOM Regional Office.

(c) You must submit with your application and post-production development report an additional report prepared by a 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 conforms to our most recent guidelines on royalty relief.

(d) You must identify the people in the CPA firm who prepared the reports referred to in paragraph (c) of this section and make them available to us to respond to questions about the historical financial information. We may also further review your records to support this information.

§ 203.82 What is MMS's authority to collect this information?

The Office of Management and Budget (OMB) approved the information collection requirements in part 203 under 44 U.S.C. 3501 *et seq.* and assigned OMB control number 1010–0071.

(a) We use the information to determine whether royalty relief will result in production that wouldn't otherwise occur. We rely largely on your information to make these determinations.

(1) Your application for royalty relief must contain enough information on finances, economics, reservoirs, G&G characteristics, production, and engineering estimates for us to determine whether:

(i) We should grant relief under the law, and

(ii) The requested relief will ultimately recover more resources and return a reasonable profit on project investments.

(2) Your fabricator confirmation and post-production development reports must contain enough information for us to verify that your application reasonably represented your plans.

(b) Applicants (respondents) are Federal OCS oil and gas lessees. Applications are required to obtain or retain a benefit. Therefore, if you apply for royalty relief, you must provide this information. We will protect information considered proprietary under applicable law and under regulations at § 203.63(b) and part 250 of this chapter.

(c) The Paperwork Reduction Act of 1995 requires us to inform you that we may not conduct or sponsor, and you are not required to respond to, a collection of information unless it displays a currently valid OMB control number.

(d) You may send comments regarding any aspect of the collection of information under this part, including suggestions for reducing the burden, to the Information Collection Clearance Officer, Minerals Management Service, Mail Stop 4230, 1849 C Street, N.W., Washington, DC 20240; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attention: Desk Officer for the Department of the Interior (1010–0071), Washington, DC 20503.

§ 203.83 What is in an administrative information report?

This report identifies the field or lease for which royalty relief is requested and must contain the following items:

(a) The field or lease name;

(b) The serial number of leases we have assigned to the field, names of the lease title holders of record, the lease operators, and whether any lease is part of a unit;

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

(d) The location of any new wells proposed under the terms of the application (not required for non-oil and gas leases);

(e) A description of field or lease history;

(f) Full information as to whether you will pay royalties or a share of production to anyone other than the United States, the amount you will pay, and how much you will reduce this payment if we grant relief;

(g) The type of royalty relief you are requesting;

(h) Confirmation that we approved a DOCD or supplemental DOCD (Deep Water expansion project applications only); and

(i) A narrative description of the development activities associated with the proposed capital investments and an explanation of proposed timing of the activities and the effect on production (Deep Water applications only).

§ 203.84 What is in a net revenue and relief justification report?

This report presents cash flow data for 12 qualifying months, using the format specified in the ''Guidelines for the Application, Review, Approval, and Administration of Royalty Relief for End-of-Life Leases'', U.S. Department of the Interior, MMS. Qualifying months for an oil and gas lease are the most recent 12 months out of the last 15 months that you produced at least 100 BOE per day on average. Qualifying months for other than oil and gas leases are the most recent 12 of the last 15 months having some production.

(a) The cash flow table you submit must include historical data for:

(1) Lease production subject to royalty;

(2) Total revenues;

(3) Royalty payments out of production;

(4) Total allowable costs; and

(5) Transportation and processing costs.

(b) Do not include in your cash flow table the non-allowable costs listed at 30 CFR 220.013 (a), (b), and (d) through (k) or:

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

(2) Damages and losses;

(3) Taxes;

(4) Any costs associated with exploratory activities;

(5) Civil or criminal fines or penalties;

(6) Fees for your royalty relief application; and

(7) Costs associated with existing obligations (e.g., royalty overrides or other forms of payment for acquiring the lease).

(c) We may, in reviewing and evaluating your application, disallow costs when you have not shown they are necessary to operate the lease, or if it appears you spent the money only to qualify for royalty relief.

§ 203.85 What is in an economic viability and relief justification report?

This report should show that your project appears economic without royalties and sunk costs using the RSVP model we provide. The format of the report and the assumptions and parameters we specify are found in the ''Guidelines for the Application, Review, Approval and Administration of the Deep Water Royalty Relief Program,'' U.S. Department of the Interior, MMS. Clearly justify each parameter you set in every scenario you specify in the RSVP. You may provide supplemental information, including your own model and results. The economic viability and relief justification report must contain the following items for an oil and gas lease.

(a) Economic assumptions we provide which include:

(1) Starting oil and gas prices;

(2) Real price growth;

(3) Real cost growth or decline rate, if any;

(4) Base year;

(5) Range of discount rates; and

(6) Tax rate (for use in determining after-tax sunk costs).

(b) Analysis of projected cash flow (from the date of the application using annual totals and constant dollar values) which shows:

(1) Oil and gas production;

(2) Total revenues;

(3) Capital expenditures;

(4) Operating costs;

(5) Transportation costs; and

(6) Before-tax net cash flow without royalties, overrides, sunk costs, and ineligible costs.

(c) Discounted values which include:

(1) Discount rate used (selected from within the range we specify).

(2) Before-tax net present value without royalties, overrides, sunk costs, and ineligible costs.

(d) Demonstrations that:

(1) All costs, gross production, and scheduling are consistent with the data in the G&G, engineering, production, and cost reports (§§ 203.86 through 203.89) and

(2) The development and production scenarios provided in the various reports are consistent with each other and with the proposed development system. You can use up to three scenarios (conservative, most likely, and optimistic), but you must link each to a specific range on the distribution of resources from the RSVP Resource Module.

§ 203.86 What is in a G&G report?

This report supports the reserve and resource estimates used in the economic evaluation and must contain each of the following elements.

(a) Seismic data which includes:

(1) Non-interpreted 2D/3D survey lines reflecting any available state-of-the-art processing technique in a format readable by MMS and specified by the deep water royalty relief guidelines;

(2) Interpreted 2D/3D seismic survey lines reflecting any available state-of-the-art processing technique identifying all known and prospective pay horizons, wells, and fault cuts;

(3) Digital velocity surveys in the format of the GOM region's letter to lessees of 10/1/90;

(4) Plat map of ''shot points;'' and

(5) ''Time slices'' of potential horizons.

(b) Well data which includes:

(1) Hard copies of all well logs in which—

(i) The 1-inch electric log shows pay zones and pay counts and lithologic and paleo correlation markers at least every 500-feet,

(ii) The 1-inch type log shows missing sections from other logs where faulting occurs,

(iii) The 5-inch electric log shows pay zones and pay counts and labeled points used in establishing resistivity of the formation, 100 percent water saturated (R_o) and the resistivity of the undisturbed formation (R_t), and

(iv) The 5-inch porosity logs show pay zones and pay counts and labeled points used in establishing reservoir porosity or labeled points showing values used in calculating reservoir porosity such as bulk density or transit time;

(2) Digital copies of all well logs spudded before December 1, 1995;

(3) Core data, if available;

(4) Well correlation sections;

(5) Pressure data;

(6) Production test results; and

(7) Pressure-volume-temperature analysis, if available.

(c) Map interpretations which includes for each reservoir in the field:

(1) Structure maps consisting of top and base of sand maps showing well and seismic shot point locations;

(2) Isopach maps for net sand, net oil, net gas, all with well locations;

(3) Maps indicating well surface and bottom hole locations, location of development facilities, and shot points; and

(4) Identification of reservoirs not contemplated for development.

(d) Reservoir-specific data which includes:

(1) Probability of reservoir occurrence with hydrocarbons;

(2) Probability the hydrocarbon in the reservoir is all oil and the probability it is all gas;

(3) Distributions or point estimates (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for the parameters used to estimate reservoir size, i.e., acres and net thickness;

(4) Most likely values for porosity, salt water saturation, volume factor for oil formation, and volume factor for gas formation;

(5) Distributions or point estimates (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for recovery efficiency (in percent) and oil or gas recovery (in stock-tank-barrels per acre-foot or in thousands of cubic feet per acre foot);

(6) A gas/oil ratio distribution or point estimate (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for each reservoir; and

(7) A yield distribution or point estimate (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for each gas reservoir.

(e) Aggregated reserve and resource data which includes:

(1) The aggregated distributions for reserves and resources (in BOE) and oil fraction for your field computed by the resource module of our RSVP model;

(2) A description of anticipated hydrocarbon quality (i.e., specific gravity); and

(3) The ranges within the aggregated distribution for reserves and resources that define the development and production scenarios presented in the engineering and production reports. Typically there will be three ranges specified by two positive reserve and resource points on the aggregated distribution. The range at the low end of the distribution will be associated with the conservative development and production scenario; the middle range will be related to the most likely development and production scenario; and, the high end range will be consistent with the optimistic development and production scenario.

§ 203.87 What is in an engineering report?

This report defines the development plan and capital requirements for the economic evaluation and must contain the following elements.

(a) A description of the development concept (e.g., tension leg platform, fixed platform, floater type, subsea tieback, etc.) which includes:

(1) Its size and

(2) The construction schedule.

(b) An identification of planned wells which includes:

(1) The number;

(2) The type (platform, subsea, vertical, deviated, horizontal);

(3) The well depth;

(4) The drilling schedule;

(5) The kind of completion (single, dual, horizontal, etc.); and

(6) The completion schedule.

(c) A description of the production system equipment which includes:

(1) The production capacity for oil and gas and a description of limiting component(s);

(2) Any unusual problems (low gravity, paraffin, etc.);

(3) All subsea structures;

(4) All flowlines; and

(5) Schedule for installing the production system.

(d) A discussion of any plans for multi-phase development which includes:

(1) The conceptual basis for developing in phases and goals or milestones required for starting later phases; and

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

(e) A set of development scenarios consisting of activity timing and scale associated with each of up to three production profiles (conservative, most likely, optimistic) provided in the production report for your field (§ 203.88). Each development scenario and production profile must denote the likely events should the field size turn out to be within a range represented by one of the three segments of the field size distribution. If you send in fewer than three scenarios, you must explain why fewer scenarios are more efficient across the whole field size distribution.

§ 203.88 What is in a production report?

This report supports your development and production timing and product quality expectations and must contain the following elements.

(a) Production profiles by well completion and field that specify the actual and projected production by year for each of the following products: oil, condensate, gas, and associated gas. The production from each profile must be consistent with a specific level of reserves and resources on the aggregated distribution of field size.

(b) Production drive mechanisms for each reservoir.

§ 203.89 What is in a deep water cost report?

This report lists all actual and projected costs for your field, must explain and document the source of each cost estimate, and must identify the following elements.

(a) Sunk cost, which are all your eligible post-discovery exploration, development, and production expenses (no third party costs), and also include the eligible costs of the discovery well on the field. 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.

(b) Appraisal, delineation and development costs. Base them on actual spending, current authorization for expenditure, engineering estimates, or analogous projects. These costs cover:

(1) Platform well drilling and average depth;

(2) Platform well completion;

(3) Subsea well drilling and average depth;

(4) Subsea well completion;

(5) Production system (platform); and

(6) Flowline fabrication and installation.

(c) Production costs based on historical costs, engineering estimates, or analogous projects. These costs cover:

(1) Operation;

(2) Equipment; and

(3) Existing royalty overrides (we will not use the royalty overrides in evaluations).

(d) Transportation costs, based on historical costs, engineering estimates, or analogous projects. These costs cover:

(1) Oil or gas tariffs from pipeline or tankerage;

(2) Trunkline and tieback lines; and

(3) Gas plant processing for natural gas liquids.

(e) Abandonment costs, based on historical costs, engineering estimates, or analogous projects. You should provide the costs to plug and abandon only wells and to remove only production systems for which you have not incurred costs as of the time of application submission. You should also include a point estimate or distribution of prospective salvage value for all potentially reusable facilities and materials, along with the source and an explanation of the figures provided.

(f) A set of cost estimates consistent with each one of up to three field-development scenarios and production profiles (conservative, most likely, optimistic). You should express costs in constant real dollar terms for the base year. You may also express the uncertainty of each cost estimate with a minimum and maximum percentage of the base value.

(g) A spending schedule. You should provide costs for each year (in real dollars) for each category in paragraphs (a) through (f) of this section.

(h) A summary of other costs which are ineligible for evaluating your need for relief. These costs cover:

(1) Expenses before first discovery on the field;

(2) Cash bonuses;

(3) Fees for royalty relief applications;

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

(5) Legal expenses;

(6) Damages and losses;

(7) Taxes;

(8) Interest or finance charges, including those embedded in equipment leases;

(9) Fines or penalties; and

(10) Money spent on previously existing obligations (e.g., royalty overrides or other forms of payment for acquiring a financial position in a lease, expenditures for plugging wells and removing and abandoning facilities that existed on the application submission date).

§ 203.90 What is in a fabricator's confirmation report?

This report shows you have committed in a timely way to the approved system for production. This report must include the following (or its equivalent for unconventionally acquired systems):

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

(b) A letter from the contractor building the system to the MMS's GOM Regional Supervisor—Production and Development, certifying when construction started on your system; and

(c) Evidence of an appropriate down payment or equal action that you've started acquiring the approved system.

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

For each cost category in the deep water cost report, you must compare actual costs up to the date when production starts to your planned pre-production costs. If your application included more than one development scenario, you need to compare actual costs with those in your scenario of most likely development. Keep supporting records for these costs and make them available to us on request.

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DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 260

RIN 1010–AC14

Royalty Relief for New Leases in Deep Water

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: The Secretary of the Interior is authorized to offer Outer Continental Shelf (OCS) tracts in parts of the Gulf of Mexico for lease with suspension of royalties for a volume, value, or period of production. This applies to tracts in water depths of 200 meters or more. This final rule specifies the royalty-suspension terms for lease sales using this bidding system.

DATES: This final rule is effective February 17, 1998.

FOR FURTHER INFORMATION CONTACT: Walter Cruickshank, Chief, Washington Division, Office of Policy and Management Improvement, at (202) 208–3822.

SUPPLEMENTARY INFORMATION:

I. Background

Legislative

On November 28, 1995, President Clinton signed Public Law 104–58, which included the Outer Continental Shelf Deep Water Royalty Relief Act (''Act''). The Act contains four major provisions concerning new and existing leases. New leases are tracts leased during a sale held after the Act's enactment on November 28, 1995. Existing leases are all other leases.

First, section 302 of the Act clarifies the Secretary's authority in 43 U.S.C. 1337(a)(3) to reduce royalty rates on existing leases to promote development, increase production, and encourage production of marginal resources on