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Minerals Management Service

30 CFR Part 203

Relief or Reduction in Royalty Rates—Deep Gas Provisions; Proposed Rule

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 203

RIN 1010–AD01

Relief or Reduction in Royalty Rates—Deep Gas Provisions

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Notice of proposed rulemaking.

SUMMARY: We (MMS) propose provisions for suspension of royalties for leases in shallow water on production associated with deep gas drilling. For a lease in the Gulf of Mexico (GOM), the proposed rule specifies the location, timing and depth of exploration and production that qualifies the lease for royalty suspension in connection with drilling for gas in deep reservoirs. Also, we propose price thresholds above which royalties must be paid even though production may otherwise qualify for royalty suspension.

DATES: MMS will consider all comments we receive by May 27, 2003. We will begin reviewing comments then and may not fully consider comments we receive after May 27, 2003.

ADDRESSES: If you wish to comment, you may mail or hand-carry comments (three copies) to the Department of the Interior, Minerals Management Service; Mail Stop 4024; 381 Elden Street; Herndon, Virginia 20170–4817; Attention: Rules Processing Team (Comments). If you wish to e-mail your comments, the address is *rules.comments@MMS.gov.* Reference ‘‘AD01—Deep Gas Provisions’’ in your subject line. Include your name and return address in the message and mark it for return receipt.

Mail or hand-carry comments with respect to the information collection burden of the proposed rule to the Office of Information and Regulatory Affairs; Office of Management and Budget; Attention: Desk Officer for the Department of the Interior (OMB control number 1010–NEW); 725 17th Street, NW.; Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Marshall Rose, Chief, Economics Division, at (703) 787–1536. In addition, MMS will hold a workshop in Houston, Texas within the comment period of the rulemaking, to explain various aspects of the rule described in the next several sections. We will announce the workshop location and date on the MMS Web site *http://www.mms.gov.*

SUPPLEMENTARY INFORMATION: Title 30 CFR part 203 regulates the reduction of oil and gas royalty under 42 U.S.C. 1337(a)(3). Under § 1337 (a)(3)(B), we may reduce, modify, or eliminate royalties on certain producing or non-producing leases or categories of leases to promote development or increased production or to encourage production of marginal resources, in the GOM west of 87 degrees, 30 minutes west longitude.

Background

This royalty suspension initiative strives to accelerate natural gas exploration, development, and production from wells drilled to deep depths on existing shallow water (less than 200 meters) leases. We define deep depths either as 15,000 feet or deeper, true vertical depth, below the datum at mean sea level (TVD SS) when a well is completed and produces from a reservoir entirely below that depth, or as 18,000 feet TVD SS when a well without completions penetrates a reservoir target entirely below that deeper depth. To date, less than 5 percent of all wells ever drilled in the 50-year history of OCS production have been to depths 15,000 feet TVD SS or deeper. The historical trend shows a relatively constant rate of recent deep drilling activity:

Number of boreholes drilled TVD SS>15,000 ft in water depths between 0–200 m

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993
Number Wells Drilled	76	32	47	50	41	41	40	34	57
Year	1994	1995	1996	1997	1998	1999	2000	2001	2002
Number Wells Drilled	70	63	67	75	60	59	94	94	74

Natural gas provides about one-fourth of the annual United States energy consumption. Approximately one-fourth of domestic natural gas is produced in Federal waters of the GOM. The National Petroleum Council forecasts that demand for natural gas will increase by 30 percent in the United States over the next 10 years. Yet, since the mid-1980's annual gas production from the OCS has exceeded additions to proven reserves each year. (Four-fifths of OCS production is currently derived from leases located in shallow water). As a result, total proven natural gas reserves on the GOM OCS have declined dramatically from nearly 46 trillion cubic feet (TCF) in 1986 to approximately 24 TCF in 1999. [Estimated Oil & Gas Reserves, Gulf of Mexico Dec. 31, 1999, OCS Report MMS 2002–007].

While the Energy Information Administration (EIA) natural gas price forecast falls below recent levels, supply may be overestimated because EIA assumptions may not fully reflect current projections regarding gas production from deepwater fields and the decline in conventional shelf gas from currently producing leases. Higher prices reflecting market concern in part have already been evident, spiking over $8 per million British thermal units (Btu) on the NYMEX Henry-Hub during the winter of 2000–2001. Such price volatility can result in higher consumer gas expenditures, while uncertain prices could contribute to under-investment in technologies for deep gas development. Although sustained high gas prices could encourage an increase in deep gas investment, the price fluctuations experienced over the last few years (ranging from $2.00-$8.00/mmbtu) contributes to a climate of uncertainty, thereby inhibiting continuing, stable investment in deep gas development. By providing royalty relief, we could dampen these effects through encouraging timely and profitable deep gas production.

Over the past 6 years, we implemented several royalty incentive programs in deep water. However, because of the long lead times associated with deepwater activity, it could be many years until deepwater production becomes a major contributor, resulting in a significant decline in OCS production of natural gas over the next 5 to 10 years. Additionally, deep drilling incentives for shallow water leases issued after 2000 cover only a small portion of the deep gas potential. Production from deep wells on existing leases in shallow water, where significant infrastructure already exists, is the most attractive source on the OCS of additional natural gas to meet the near and mid-term energy needs of the nation.

Summary of the Deep Gas Royalty Relief Program

This summary integrates the various components of our proposed royalty relief provisions for deep gas production in shallow water. On designated leases, we would suspend royalty payments after certain deep drilling activities and outcomes occur. A lease would be eligible to receive this royalty relief if it:

(1) Was issued in a lease sale held before January 1, 2001;

(2) Is located in the GOM entirely in water depths less than 200 meters on a block wholly west of 87 degrees, 30 minutes west longitude; and

(3) Has not produced gas or oil from a well that commenced drilling before the publication date of this proposed rule in the **Federal Register** with a completion 15,000 feet TVD SS or deeper.

A lease could qualify for a royalty suspension volume that may be applied to subsequent deep gas production from the lease, or allocated from other deep wells drilled after the date of this proposed rule in the **Federal Register**, if it:

(1) Has completed a successful well 15,000 feet TVD SS or deeper that commenced drilling after the publication date of this proposed rule in the **Federal Register**; and

(2) Has production of gas from that completed deep well before five years after the effective date of the final rule.

A lease could qualify for a royalty suspension supplement that may be applied to any subsequent gas and oil production from or allocated to the lease if it:

(1) Has an unsuccessful well that targets a reservoir on the lease at a depth of at least 18,000 feet TVD SS, and the drilling commenced after the publication date of this proposed rule in the **Federal Register** but no later than five years after the effective date of the final rule;

(2) Has started drilling that unsuccessful sub-18,000 foot well before producing from a deep well on the lease; and

(3) Receives subsequent confirmation from MMS that the drilling effort was deep enough but unsuccessful. We rely on data that the lessee provides within 60 days after the well reaches its total depth.

The following table shows the royalty suspensions, in BCF, we propose for various categories of leases that have not produced from wells deeper than 15,000 feet TVD SS.

ROYALTY SUSPENSION VOLUMES AND ROYALTY SUSPENSION SUPPLEMENTS FOR DEEP GAS

[0–200 meters water depth]

Reservoir depth (TVD SS)	For a successful qualified deep well, a lease receives	For an unsuccessful certified well, a lease receives
From 15,000 to less than 18,000 feet	15 BCF	None.
18,000 feet or deeper	25 BCF	5 BCF.

In addition, MMS is also soliciting comments on two other RSV levels. Option B would provide 10 BCF for wells 15,000–18,000 ft deep, and 25 BCF for wells >18,000 ft. Option C would provide 10 BCF for wells 15,000–18,000 ft deep, and 20 BCF for wells >18,000 ft. Both options B and C would result in less incremental production and a reduction in lost royalties. For a fuller discussion of the relative merits of these alternatives, please see the section addressing Executive Order 12866.

A lease could obtain up to two royalty suspension supplements plus the royalty suspension volume associated with the first successful qualified deep well to start production. Thus, a lease could earn the right to produce up to as much as 35 BCF of natural gas royalty free, that is, 10 BCF because of two unsuccessful wells and then 25 BCF from a successful well.

A lessee or successor lessee may apply any remaining royalty suspension volume from the lease's successful qualified deep well to any natural gas production from subsequent deep wells drilled and completed on the lease. However, the suspension amount allocated to deep gas wells less than 18,000 feet TVD SS cannot exceed 15 BCF.

Accordingly, a successful qualified deep well must be located on the lease before it may use any royalty suspension volume. Therefore, if a lease is in a unit and is allocated production from a deep well on another lease in the unit, the first lease will receive no royalty suspension volume unless it also has a successful qualified deep well. Further, once production begins from a successful qualified deep well on a lease, the lessee must use the applicable royalty suspension volume for all production from deep wells on or allocated to that lease and drilled after this rule is published in the **Federal Register**. In other words, the lessee cannot delay applying the royalty suspension volume to applicable production.

The royalty suspension supplement would be used against any gas and oil produced from the lease targeted by the unsuccessful certified well, however, the lessee first must file the information we need to confirm the supplement. A lessee would not obtain both a full royalty suspension volume and a full royalty suspension supplement from the same wellbore. If an unsuccessful certified well later produces, then any portion of the royalty suspension supplement taken (plus gas and oil produced during periods when gas prices exceed the price threshold) would have to be subtracted from any royalty suspension volume earned. Also, the lessee could not use any remaining royalty suspension supplement earned from that wellbore.

The deep gas relief provisions for active leases would be subject to a natural gas threshold price of $5 per million Btu, adjusted from year 2000 for inflation. If the average annual NYMEX natural gas price exceeds this adjusted level for that full calendar year, the lessee would have to pay full royalties on any production of natural gas or oil that would otherwise have royalties suspended due to royalty relief from a successful qualified deep well or royalty suspension supplements. Moreover, the volume produced during such a calendar year would count against the eligible royalty suspension volumes and royalty suspension supplements.

A shallow water lease issued in a sale held after January 1, 2001, but before the effective date of this final rule, may substitute the provisions proposed here for the deep gas incentive terms in the lease. If a lease is eligible and the lessee chooses to substitute, then the lessee would have to do so within 180 days of the final rule's effective date.

Details of Proposed Royalty Relief for Deep Gas Production

The Deep Water Royalty Relief Act of 1995 (DWRRA) (Title III of Pub. L. 104–58) provides authority to grant royalty relief to non-producing leases to encourage industry to lease, explore, develop, and produce oil and gas resources west of 87 degrees, 30 minutes west longitude in the GOM. Until now, we have not exercised that royalty relief authority for existing shallow water leases, *i.e.*, those located in water less than 200 meters deep. There have been few financial and technical obstacles on shallow water leases to drilling and initiating production, the large majority of which is from reservoirs less than 15,000 feet TVD SS.

In contrast, reservoirs deeper than 15,000 feet TVD SS are relatively unexplored in the potentially prospective and otherwise extensively explored shallow waters of the GOM. Some 10 TCF of gas have already been discovered in these reservoirs, mostly in drilling depths between 15,000 and 18,000 feet TVD SS. We estimate that another 5 to 20 TCF of gas are technically recoverable in undiscovered deep reservoirs, with the majority being located at depths below 18,000 feet TVD SS. Focused economic incentives can encourage exploration for and recovery of this huge resource potential.

Over 5,000 exploration wells were drilled in shallow water during the past 10 years, but only seven percent reached drilling depths between 15,000 and 18,000 feet TVD SS, and just two percent were deeper than 18,000 feet TVD SS. Less than two percent of all currently active leases in shallow water have had a gas well drilled 18,000 feet TVD SS or deeper. Relatively few deep wells have been drilled, in part because they are expensive due to unconventional rig specifications, the potential for high pressure and temperature conditions, and the presence of corrosive gas, all of which increase the costs of support facilities. Further, deep wells face a high risk of failure and require the discovery of large resource accumulations, with the potential for high flow rates, to be economic.

To accelerate the discovery and production of natural gas to meet the nation's growing energy needs, we propose to suspend some royalty obligations for certain existing GOM leases in shallow water that drill new deep wells and produce natural gas. In case of a directional well, the lease block on which the completion of the new deep well occurs qualifies for the royalty suspension volume. A new well does not utilize an existing wellbore. We chose the royalty suspension volume as our mechanism for royalty relief because of several advantages it has over other systems of relief, such as providing a fixed dollar amount incentive or a reduction in the royalty rate. Royalty volume suspensions have been used extensively in the GOM (deepwater relief and deep gas relief for new leases). Both MMS and industry have experience and practical knowledge with this form of royalty relief. Royalty suspension for a volume rather than a value of production avoids a number of accounting problems and resulting conflict. The royalty suspension volume, rather than a reduction of royalty rate, provides more certainty to the lessee because, to the extent the royalty suspension volume is produced, it is more difficult for the agency to try to take away the royalty relief. In contrast, a decision to reduce the royalty rate might be reversed anytime over the life of production, and hence provides less certainty about receipt of a potentially large part of remaining royalty relief. Additionally, revenues received in the future are generally worth less to industry (i.e., higher private discount rate) than to government (i.e., lower social discount rate). Thus, providing upfront relief can be structured to be more valuable to the lessee and no more costly to the government than would a drawn out system of relief. For these reasons of practicality and efficiency, a royalty suspension volume is our mechanism of choice.

A lease must meet three criteria to be eligible for a royalty suspension under proposed § 203.40.

- The lease must predate the year 2001, when we began issuing new leases with deep gas production incentives, or the lessee must have exercised the option offered under § 203.48.
- The lease must be located in an area for which we have authority to offer royalty relief for new development.
- The lease must not have produced from a well with a perforated interval the top of which is 15,000 feet TVD SS or deeper, if that well commenced drilling before the publication date of this proposed rule in the **Federal Register**.

When deep gas production has previously occurred on the lease, or if drilling of a well that subsequently results in deep gas production began prior to publication of this proposed rule, then there is no reason to provide royalty relief, i.e., a financial incentive to drill and extract deep gas resources. Yet, if deep gas production does not occur before the existing infrastructure is abandoned, then the deep gas resources are less likely to be produced later.

We propose to make the royalty relief available as of the date of this proposed rule so lessees will not delay drilling new deep gas wells between the date we announce the incentives in the proposed rule and the date they would normally become effective with publication of the final rule. Of course, there is no guarantee that we will adopt a final rule for deep gas royalty relief. Moreover, though a lease could qualify for the incentive with a new deep gas well with drilling activity after the date of the proposed rule, the lessee could apply the royalty relief only to production occurring after the effective date of any final rule.

We also propose volume suspension levels that vary according to the drilling depth of the well. The incentive levels we propose for pre-2001 leases differ from the single, deep gas volume suspension with which we have recently offered new leases in shallow water. The variation in incentives across well depth categories for pre-2001 leases reflects the differing costs, risks, and resources that exist at selected well depth levels. Though this feature makes the rule more complicated, we feel it is necessary to adjust incentives to the differing needs for different drilling depths. Also, no bonus bid that reflects the value of the incentive on an individual lease is involved. It is more important to fine-tune incentive levels for these pre-2001 leases than it is for new leases.

Royalty Suspension Volumes for Successful Qualified Deep Wells

In proposed § 203.41, we specify a royalty suspension volume per lease of 25 billion cubic feet (BCF) for natural gas production from new wells on a lease block with completions that are entirely 18,000 feet TVD SS or deeper. This proposed relief level is based on estimates of the minimum reservoir size necessary for exploration and development to be economic at an expected landed price of about $3.50/thousand cubic feet (Mcf), accounting for various costs and risk factors. Our price assumption is based on the recent natural gas price level and in-house forecasts rather than EIA wellhead gas projections. A suspension of the typical 1/6th royalty obligation increases the set of potential drilling targets by reducing the minimum size of an economically recoverable reservoir. To determine the suspension volume amounts, a combination of factors, including minimum economic field sizes, costs, and risks, were balanced to encourage deep gas production at the present time. We estimate that a 25 BCF royalty suspension volume reduces the size of a reservoir worth exploring immediately at these depths by 15 to 20 percent (in a typical case, from 48 to 40 BCF), and an additional 15 to 20 percent when combined with the royalty suspension supplement portion of the program discussed later. Also, this same program of relief would tend to accelerate the search for natural gas by making projects planned for future drilling economic sooner. Therefore, it would encourage earlier exploration of many additional reservoirs. This acceleration effect will make it profitable to drill and produce immediately some reservoirs with relief, rather than to defer these activities for 5–10 years without relief. We expect this incentive will spur earlier exploration activity for reservoirs that are smaller than 90 BCF, which is the level at which prompt exploration is currently optimal without any incentives. Our latest assessments indicate that about 75 percent of all the undiscovered, but technically recoverable deep gas reservoirs are smaller than 90 BCF. Thus, we expect our program to substantially increase the number of wells that will be drilled earlier than they otherwise would be.

We propose a royalty suspension volume per lease of 15 BCF on natural gas production from new wells on a lease block with completions in the interval from 15,000 to less than 18,000 feet TVD SS. The smaller proposed royalty suspension volume for natural gas production from wells drilled in this depth interval is appropriate because the costs of drilling are significantly lower and the chances of success higher than for wells deeper than 18,000 feet TVD SS.

Recent American Petroleum Institute (API) surveys (Joint Association Survey on 1999 and 2000 Drilling Costs, API, Independent Petroleum Association of America, and Mid-Continent Oil & Gas Association) show that typical costs to drill prospects in the 15,000 to 18,000 foot depth interval on the OCS run a little more than one-half as much as drilling deeper than 18,000 feet TVD SS. Moreover, we estimate success rates for future wells drilled in the 15,000 to 18,000 foot depth interval to be two-thirds higher than the success rate for wells drilled deeper than 18,000 feet TVD SS. Thus, the 15 BCF royalty suspension volume is determined to accelerate drilling for reservoirs between 15 and 50 BCF. We estimate reservoirs of the 35 to 50 BCF size can be drilled profitably in the near future with relief, but would be delayed considerably under current conditions without relief. Thus, reservoirs larger than 50 BCF are the current target size that adequately accommodates the economic risks and costs of drilling gas wells in the better-known geologic formations in the 15,000 to 18,000 foot depth interval.

Administratively, production from the first successful qualified deep well would establish the royalty suspension volume for the lease. To qualify, the lessee must notify the MMS Regional Supervisor for Production and Development of intent to commence drilling the deep well and production would have to begin from the deep well no later than five years after the effective date of the final rule, so that the program benefits can be realized sooner rather than later. We require notification of intent to drill deep wells partly because if the lease is participating in the Royalty-in-Kind (RIK) program, we need to be alerted in advance of any activities that could affect the placement of RIK production by the Minerals Revenue Management (MRM) organization of MMS. Under the RIK program, the government accepts royalties in product rather than in cash and sells it under contract as described at *www.mrm.mms.gov/rikweb.*

The royalty suspension volume is applied to deep gas production beginning the day that the lessee notifies MMS that deep gas production has begun. Also, if production begins from a well in the 15,000 to 18,000 foot depth interval, the royalty suspension volume for the lease would not increase above the level applicable to that well, even if the lessee later completes a well deeper than 18,000 feet TVD SS. We propose this stipulation because the initial success of a deep well reduces the risks associated with subsequent deep wells sufficiently to eliminate the need for an added incentive to drill even deeper wells. The incentive is to promote drilling of the primary target, not subsequent secondary ones. We rely on the drilling of a new well (subsequent to the date of the proposed rule), that is completed to a reservoir of certain depth as the indicator of response to the incentive, as opposed to conditioning relief on drilling into a new reservoir. This way we avoid the potential complications associated with delineating the boundaries of the reservoir across multiple leases. These royalty suspension volumes for deep gas production would not override the minimum royalty or rental obligations of the lease and unused portions would be transferable to a successor lessee.

Proposed § 203.42 authorizes application of the royalty suspension volume to gas production from other deep wells on, or allocated under an approved unit agreement to, the lease, subject to several conditions designed to increase deep drilling. The lease to which the production is allocated must have its own successful qualified deep well. Also, drilling of other deep wells from which production is allocated to your lease has to begin after the publication date of this proposed rule in the **Federal Register**. But this allocated production may come from a lease on the unit that does not have or is ineligible for a royalty suspension volume. For example, your neighboring lease within the unit may have drilled a deep well before the qualifying date and therefore disqualifying that lease for relief. Yet, a subsequent well drilled after the qualifying date on that lease does allow royalty-free production to be allocated to your lease. While production from deep wells on the unit can be allocated across leases, the royalty suspension volume from other leases on the unit may not be allocated across leases. Under these conditions, the production to which your royalty suspension would apply includes allocated production from other deep wells within the unit.

The royalty relief, in the form of a royalty suspension volume, may not be applied to production from shallow wells or to hydrocarbons other than gas. The royalty suspension volume applies to the gas production volume as reported on the Oil and Gas Operations Report, Part A (OGOR–A). Note that if the gas is transferred to a gas plant for processing prior to sale, the gas production volume reported on the OGOR–A will be higher than the residue gas volume attributable to the deep gas well.

Notwithstanding a unit agreement, we propose generally to maintain a simple lease-based relief structure by restricting a royalty suspension volume to the lease on which a deep well is completed and the royalty suspension supplement (as described later in this preamble) to the lease on which a deep well is targeted. This approach is consistent with existing administrative designations relating wells to leases. It also avoids the need to regulate decisions about the participating area and the allocation of a royalty suspension volume across a joint operation. We believe that lessees on a unit contemplating drilling a deep well jointly can work out financial arrangements to cover a broad variety of circumstances, e.g., a situation where those unitized leases without a deep well would have to pay royalty on any production allocated to them from the deep well. To help us assess the validity of this inference, we would like responses to the following question: In comparison to the proposed approach, under what conditions would a royalty suspension volume or supplement allocated among several leases within a unit result in either more deep drilling or less administrative burden?

The royalty relief would end as soon as cumulative qualified production from or allocated to the lease with the successful qualifying deep well reaches the royalty suspension volume. This differs from royalty suspensions in deep water, where the relief lasts through the end of the month when production reaches the royalty suspension volume. We propose this difference because the time duration over which suspension volumes are taken is much shorter for deep gas than for deepwater royalty relief. Taking into account the expected production rates and volume suspension levels, we believe that leases with the proposed deep gas relief would use four times the portion of the applicable royalty suspension volume that a deepwater field would use in a month. This means that in cases where the relief volume for deep gas is reached early in the month, extension of relief throughout the month would provide a much larger proportional increase in that part of a lease's total production that is royalty-free in comparison to the deepwater paradigm. Continuing royalty suspension through the end of the month typically would add over two percent to total deep gas relief, versus only 0.5 percent to total deep water relief, on a lease whose cumulative qualified production reached the prescribed suspension volume on the first day of the month.

Once production commences from a successful qualified deep well, the lessee is to notify us within 30 days to confirm the royalty suspension volume. The confirmation promotes understanding and agreement of royalty terms and helps avoid confusion when a lease has both royalty-bearing and royalty-free production. *See* proposed § 203.43.

Royalty Suspension Supplements

The probability of future drilling success is anticipated to be relatively low in the case of drilling 18,000 feet TVD SS or deeper. To offset this high risk, we propose an incentive for drilling even unsuccessful exploration wells to at least 18,000 feet TVD SS (hereafter sub-18,000 foot well). A small supplemental royalty suspension volume for an unsuccessful well along with a larger royalty suspension volume for a successful well is a more cost-effective incentive than a royalty suspension volume alone. As with the royalty suspension volume, the lease block with the reservoir targeted by the new sub-18,000 foot well qualifies for the royalty suspension volume.

This supplemental royalty suspension is important because providing larger royalty suspension volumes only for successful wells becomes progressively less effective in encouraging new development as the suspension size increases. First, each extra unit of relief is captured later in the production profile and, hence, is less valuable to the operator. Second, the potential to use all the suspension volume declines when it exceeds the expected size of the initially discovered deep reservoir. Less than 10 percent of the leases having a deep-well discovery found more than a single reservoir in the deep depths. Third, it is also possible that some operators value the opportunity to minimize the costs of failure more than enhancing the benefits of success. In proposing to set the royalty suspension volume and royalty suspension supplement levels, our analysis takes into consideration the inter-relationship between royalty relief for successful and unsuccessful drilling efforts on expected lease profitability. Consequently, we would be able to reduce the suspension volume amounts for successful deep well drilling as a result of adding the royalty suspension supplement option, while generating at least as much incremental effect on future drilling activity.

A royalty suspension supplement offers other program benefits by reducing the magnitude of the royalty suspension volumes for successful drilling. Large suspension volumes only for successful wells provide more of the relief to reservoirs that would have been drilled promptly and profitably without any royalty relief. Also, with rapid improvements in technology, smaller suspension volumes for successful drilling could become appropriate. Because we set program parameters years before the program expires, we need to be careful not to promulgate incentives at levels that could become higher than necessary. Accordingly, it is fiscally prudent to accelerate deep gas production with different types of drilling incentives for selected kinds of leases that recognize the variations in drilling costs and risks across drilling depth categories.

Along with volume suspensions on successful deep wells, § 203.44 proposes relief for unsuccessful certified wells, 18,000 feet TVD SS or deeper, in the form of a five BCF royalty suspension supplement. To avoid incentives that would distort reasonable drilling efforts, we propose to share only part of the cost. Thus, we set the value of the royalty suspension supplement for drilling an unsuccessful certified well below the full cost of exploration and below the magnitude of the royalty suspension volume for drilling a successful well. Because of the significantly greater cost and risk for drilling 18,000 feet TVD SS or deeper, we would offer the royalty suspension supplement only for drilling to these very deep reservoir targets.

An unsuccessful certified well is defined in proposed § 203.0 as a well that is:

- Drilled but not completed to a depth of at least 18,000 feet TVD SS;
- Targeting a reservoir identified from seismic and related data, that does not produce or that MMS agrees is not commercially producible (by computing minimum developable reservoir sizes for that drilling depth using geological and geophysical data, resource magnitudes and timing of production, price forecasts, and industry required rates of return); and
- On which drilling begins:

(1) After the publication date of this proposed rule,

(2) Before five years after the effective date of the final rule, and

(3) Before there is any production from a successful qualified deep well on that lease.

Under this proposed provision, MMS would not allow any royalty suspension supplement if the lessee starts drilling the unsuccessful sub-18,000 foot well after gas or oil has been produced from any deep well on the lease. Also, the lessee is to notify the MMS Regional Supervisor for Production and Development of the intent to commence drilling a sub-18,000 foot well. Then, after drilling the well, the lessee is to provide the data necessary to confirm an unsuccessful well within 60 days after the well reaches its Total Depth (TD) deeper than 18,000 feet TVD SS. Such data may include well test data, seismic and economic data that prove the well met the standard of an unsuccessful certified well. We seek notification of intent to drill sub-18,000 foot wells in part because the lease may be participating in the RIK program and MMS will need to have advance notification to manage the RIK oil and gas workload. We would set the 60-day deadline so that our review and concurrence in the non-commerciality of the well occur close to the same time and, thus, with about the same market conditions as when the lessee drilled the well. Shortly after receiving the necessary data, we intend to send a notice confirming or denying that the lease has earned the royalty suspension supplement.

For a well that falls below specified producibility standards or that we agree is non-commercial and which satisfies the post-drilling administrative requirements, we would then grant the lease a royalty suspension supplement. The supplement takes the form of a specified royalty suspension for use against gas or oil production on, or allocated under an approved unit agreement to, the same lease that occurs on or after the date the lessee files the data confirming failure. A lease-specific process for applying the royalty suspension supplement is the broadest we have legal authority to offer. Proposed § 203.44(b) specifies that we would allow royalty suspension supplements for up to two unsuccessful certified wells per lease (so as not to reduce the incentive to try again after an initial failure). Of the 61 leases in our data base that have been drilled to very deep depths, only one lease had more than two failed wells without having a success. We also would not allow more than one royalty suspension supplement from a single wellbore. For these and other reasons explained below, we are confident that the provision for up to two modest size supplements would not create incentives for incurring costs with only remote possibilities of success.

In § 203.45, we propose prompt use of this royalty suspension supplement, beginning the first day of the month the lessee files data with MMS confirming lack of success. We will allow the lease to retain the supplement if the lease has no other production against which to apply it at the time of this filing. In these cases the royalty suspension supplement is to be used beginning on the first day of the month that lease production starts.

Any royalty suspension supplements earned during the qualifying period up to five years after this rule becomes effective would remain available until used, until forfeited under proposed § 203.44(c), or until the lease expires. As is the case with royalty suspension volumes for deep gas production, these royalty suspension supplements would not override the minimum royalty or rental obligations of the lease and unused portions would be transferable to a successor lessee.

Also, the royalty relief would end as soon as the cumulative qualified production reaches the royalty suspension supplement. This procedure is even more critical in the case of an unsuccessful well than for successful drilling. This is because the royalty suspension supplement is applied to all of a lease's production. In cases where the cumulative production reaches the royalty suspension supplement early in the month, most of that month's production should pay royalties. Without this timing provision, the cumulative amount of these smaller royalty suspension supplements may be reached early in a month, and all lease production for the remainder of the month would generate an unintended yet relatively large royalty-free windfall to the lessee.

Bounds on Royalty Suspension Supplements

A lessee could earn the royalty suspension supplement only by starting to drill a sub-18,000 foot well on the lease *before* any deep well on the lease produces. We don't propose to offer the royalty suspension supplements after a successful well because following a deep well discovery, the risk associated with further drilling is reduced substantially. We propose to reserve the combined incentive of royalty relief for both successful and unsuccessful wells to lessees that attempt to deepen significantly their productive horizon. For example, drilling a new well to 19,000 feet involves substantially more uncertainty on a lease that only experienced production from a 12,000-foot well than on a lease that already generated production from a 17,000-foot well. Hence, we believe only the former lease requires additional encouragement to drill deeper than 18,000 feet TVD SS, which we would provide in the form of a royalty suspension supplement.

As proposed in § 203.41(c), any royalty suspension volume a lease earns adds to any royalty suspension supplement the lease already has. However, if drilling on a well that ultimately reaches 18,000 feet TVD SS or deeper starts after the lease produces gas or oil from a deep well 15,000 feet TVD SS or deeper, then the lease would not earn any royalty suspension supplement.

Also, a lease could not obtain both a full royalty suspension volume and a full royalty suspension supplement within a single wellbore, as proposed in § 203.41(c). In this situation, the aggregate royalty suspension is unnecessary because another entire well cost is not involved.

Nevertheless, after a well earns a royalty suspension supplement for unsuccessful drilling, economic conditions may improve resulting in deep gas production from the same wellbore. In this case, the lease would receive a royalty suspension volume if the well meets the criteria for a successful qualified deep well. That means production must begin before five years after the date of the final rule, and the well must be the first deep well to produce gas from the lease. Proposed § 203.44(c)(1) addresses this situation. It is designed to prevent a lessee from ''double dipping'' in royalty relief. Thus, a lessee would have to subtract any royalty suspension supplement used on other lease production from the royalty suspension volume applied to successful qualified deep gas production from the same wellbore (15 BCF from a 15,000—18,000 feet TVD SS well, and 25 BCF from a well more than 18,000 feet TVD SS). Further, the lessee would forfeit any unused royalty suspension supplement earned from that wellbore.

For example, suppose the lease has used three BCF of a royalty suspension supplement and then produces gas from the same wellbore used to qualify for the royalty suspension supplement under circumstances that qualify the well as a successful qualified deep well. Then, the used three BCF royalty suspension supplement must be subtracted from the royalty suspension volume allowed for the successful qualified deep well and the lease qualifies for a royalty suspension volume of 12 BCF or 22 BCF, depending on the depth of the deep producing well. The remaining unused two BCF of the original royalty suspension supplement is forfeited.

Proposed § 203.44(c)(2) addresses the unusual, though possible, situation in which the following sequence of events occurs:

(1) An unsuccessful certified well earns a royalty suspension supplement,

(2) Production from shallower reservoirs on the lease use the royalty suspension supplement,

(3) A successful qualified deep well through a different wellbore earns a royalty suspension volume,

(4) The royalty suspension volume exceeds the volume produced from that well, and

(5) The wellbore originally used to qualify as an unsuccessful certified well later produces.

In that case, the unused royalty suspension volume from the successful qualified deep well could be applied to production from the originally unsuccessful deep wellbore under proposed §§ 203.41 and 203.42. But in some circumstances, that could result in ''double dipping'' from the originally unsuccessful wellbore.

For example, assume the lessee drills an unsuccessful certified well, and earns the five BCF royalty suspension supplement. Further assume that the entire royalty suspension supplement is applied to production from shallower wells. Then assume that the lessee drills a successful qualified deep well to a depth of 19,000 feet TVD SS and thereby earns a royalty suspension volume of 25 BCF. Finally, assume that the successful qualified deep well produces only three BCF of gas. In this situation, the lessee still has 22 BCF of royalty suspension that may be applied to other deep gas production from the lease. Then assume that economic conditions change, resulting in deep gas production through the originally unsuccessful wellbore-the same wellbore originally used to qualify for the royalty suspension supplement. If enough production emerges from that wellbore it could be responsible for the five BCF of royalty suspension supplement already used, plus the 22 BCF of royalty suspension volume remaining from the successful qualified deep well. The total relief of 27 BCF exceeds the amount we allow from a single wellbore drilled to this depth.

Proposed § 203.44(c)(2) is designed to avoid this result. Under this provision, the lessee could use only 20 BCF of the royalty suspension volume remaining from the successful qualified deep well, resulting in a total of 25 BCF of royalty relief derived from that wellbore. This stipulation applies the same principle reflected in proposed § 203.44(c)(1). If the originally unsuccessful wellbore shares the incentive earned by a successful qualified deep well, the lessee subtracts whatever portion of the royalty suspension supplement has been applied to other production from the royalty suspension volume used by the originally unsuccessful well that later produces.

Price Thresholds

Another component of the proposed deep gas provisions is the stipulation of a $5.00 per million Btu price threshold, adjusted from year 2000 for inflation, as described in proposed § 203.47. When average market gas prices remain above this threshold amount for an extended time, which we define as one calendar year, deep gas projects will benefit significantly more from favorable market conditions than generally expected. No royalty relief will typically be necessary during such periods, because market price alone offsets the need for royalty relief and should be sufficient reward for attaining the desired increase in exploration and development activities related to deep depth drilling. In times of prices above the threshold, relief in the form of royalty suspension supplements or volumes would no longer be needed. Lessees would then pay appropriate royalties and that same production would count against the royalty suspension supplements and volumes. If this production were not to count against the royalty suspension volume or supplement, the only offset would be a delay in benefits from royalty relief—hardly enough to justify using a price threshold mechanism.

If the market price of natural gas later falls below the prevailing price threshold, royalty relief would be reinstated, up to the remaining suspension volume. That feature serves to keep marginal fields profitable and to accelerate production of additional gas supplies.

We employ the price threshold specified as a dollar value, escalated for inflation. Other types of price thresholds, such as a sliding scale or a continuous function, were considered but not chosen, primarily to be consistent with past practices. Our relief programs in the GOM region have used the same price threshold approach. When this type of threshold is exceeded, relief is lost only for that year and the lessee more than offsets the loss of relief by the gain in revenues received from the higher market price.

The proposed $5.00 per million Btu price threshold is higher than natural gas thresholds set in other royalty relief programs because the focus of this program is to accelerate deep gas drilling and production. This short-term focus contrasts with inducing investment in new infrastructure such as platforms and pipelines and developing marginal properties, which is the longer-term goal of our deepwater program. The greater volatility of recent gas prices has raised uncertainty about price expectations over the next several years. In light of this increased price uncertainty, we believe it prudent to elevate the price level that would interrupt this royalty relief. Thus, raising the threshold price level would provide greater assurance that royalty relief will be realized and so would encourage timely exploration and earlier production from discoveries.

We found that the anticipated increase and acceleration of drilling induced by the relief program is similar to the effect that would occur without relief if gas prices rose from $3.50 to $5.00 per million Btu. So, during periods when market gas prices reach $5.00 per million Btu, adjusted for inflation, we can safely eliminate royalty relief without adversely affecting the attainment of program goals. In contrast, our deepwater program targets long-term development and infrastructure incentives for which short-term price fluctuations are less likely to affect decisions. The deep gas program is short term—thus economically justifying a higher natural gas price threshold before royalty relief

Transition Option for New Leases Issued in Sales Held after January 1, 2001

In § 203.48, we propose to allow leases issued in sales held after January 1, 2001 (post-2000 leases), but before the effective date of the final rule, to exercise a one-time transition option. The transition option would be the opportunity to replace the royalty relief provided for in the original lease instrument, if any, relating to deep depth drilling with the alternative terms that would be offered to all pre-2001 leases in shallow water under this proposed rule. The leases must be located in the GOM wholly west of 87 degrees, 30 minutes west longitude. This one-time option would have to be exercised within 180 days after the effective date of the final rule. Note that some elements of the deep gas royalty relief, such as the volume suspensions for the 15,000- to 18,000-foot TVD SS wells, are more favorable for at least some post-2000 leases than for pre-2001 leases. Yet other elements, such as price threshold levels and the royalty suspension supplements, are more favorable to pre-2001 leases than to at least some post-2000 leases. Each individual lessee could determine the most favorable set of terms for its particular post-2000 lease. Nevertheless, the option would be irrevocable, and once exercised, the lease would be subject to all the requirements for royalty suspension applicable to a pre-2001 lease. In particular, if the lease produced oil or gas from a well that commenced drilling in deep depths before the publication date of this proposed rule, then no suspension volumes or supplements would be available upon conversion.

While the option to change deep gas incentive terms may give some of the post-2000 leases a benefit for which the lessees did not fully bid, the leases issued before 2001 will receive the full deep gas benefit for which the lessees did not bid at all. Therefore, we feel that, in fairness, those lessees of post-2000 leases who may have paid some premium for the deep gas incentive in their lease terms should have the opportunity to get at least as favorable terms as those lessees who paid nothing for the incentive. Thus, allowing lessees of post-2000 leases with some deep drilling royalty relief to substitute in their lease terms the alternative terms for pre-2001 leases under this proposal would ensure consistency and fairness.

Additionally, if more lessees choose the transition option, the program would benefit through increased deep gas development.

The following table displays the various deep gas lease terms depending upon whether § 203.48 is exercised. Note that lessees of post-2000 leases could replace their royalty relief and deep gas drilling terms with those available to pre-2001 leases, but could not substitute different post-2000 lease terms (that is, lessees of Sale 178 leases cannot choose those terms applicable to Sale 182 leases). Moreover, if a post-2000 lease was issued without any royalty relief for deep drilling in shallow water, the lease could not claim the benefit of the terms for deep drilling associated with pre-2001 leases as described in this proposed rule. If a post-2000 lease already has used some royalty suspension volume and requests this transition option, then we would deduct the used royalty suspension volume from the substituted royalty suspension volume. The supplement is not affected as long as the criteria for royalty relief from drilling an unsuccessful well are met (e.g., drilling starts on the unsuccessful well deeper than 18,000 feet TVD SS after the publication date of this proposed rule). Finally, we do not allow a reverse conversion: lessees cannot replace the terms offered in this proposed regulation to leases in existence on January 1, 2001 with those terms we already made available to post-2000 leases when they were sold.

In summary, if we issued a shallow water lease in a sale held after January 1, 2001, but before the effective date of this final rule, the lessee may substitute the provisions proposed here for the deep gas incentive terms in the lease. If a lease is eligible and the lessee chooses to substitute, then the lessee would have to do so within 180 days of the final rule's effective date. Once this option is selected, the post-2000 lease is treated administratively like a pre-2001 lease for royalty suspension purposes. Accordingly, to obtain the full drilling and production benefits derived from activities undertaken before exercising this option, lessees of post-2000 leases must satisfy the same timing milestones required of pre-2001 leases, including activities undertaken during the period before the effective date of the final rule.

ROYALTY RELIEF FOR EXISTING AND NEW LEASES

Program element	Proposed relief terms for existing leases	Sale 178 lease terms	Sales 180, 182, 184, 185 lease terms
A Successful Qualified Deep Well from 15,000 to less than 18,000 feet TVD SS.	15 BCF	20 BCF	20 BCF
A Successful Qualified Deep Well 18,000 feet TVD SS or deeper	25 BCF	20 BCF	20 BCF
An Unsuccessful certified well 18,000 feet TVD SS or deeper	*5 BCF	0 BCF	0 BCF
Maximum royalty suspension per lease	35 BCF	20 BCF	20 BCF
Price Threshold Above Which Royalties Are Due	$5/MMBTU	$3.50/MMBTU	$5/MMBTU

*5 BCF per unsuccessful certified well may be earned for up to 2 unsuccessful certified wells with a maximum of 10 BCF per lease.

Sidetracks

The royalty suspension volumes we propose apply to deep gas production from new wells. A new well is one that does not use an existing wellbore. Drilling efforts that use a new wellbore to bypass lost tools, etc., or straighten crooked holes would qualify as a new well. We propose to require a new wellbore because inclusion of sidetracks would be complicated to administer and most sidetracks are substantially less costly than a new wellbore. Therefore, we chose the proposed royalty suspension volumes based on the cost of a completely new well.

The complication with sidetracks arises primarily due to the fact that the offset distance (kick off point to total depth) of drilling a sidetrack, and thus the cost, of a sidetrack is generally more variable than for a new well drilled to a given depth interval. While the sidetrack from near the top of an existing well may cost almost as much as a new well, a sidetrack from, for example, 14,000 feet down to a 16,000 foot reservoir should be less costly. Recent API surveys show average drilling costs of a sidetrack are from one-half to two-thirds those of a new well, largely because the average length drilled is half or less.

Though it may appear conceptually desirable to do so, we have not proposed a royalty relief instrument for new deep sidetracks for several reasons. One, providing the same amount of royalty suspension volume for all new deep sidetracks as compared to new deep wells is neither fair nor cost-effective since it would result in a windfall for those fortunate enough to have sidetrack opportunities. Two, the cost data we currently have available on sidetrack drilling are not sufficiently exhaustive on length and drilling depth to allow us to conduct the same in-depth analysis that we undertook for determining the appropriately-sized royalty suspension volumes for new deep wells. With the exception of the prolific Norphlet trend, so little side-track drilling has taken place at deep depths that historical evidence alone may not offer a sufficiently reliable guide about these relationships to allow us to determine the proper level of incentives for deep sidetracks. Three, based on the cost data and drilling observations we do have, the expected net cost of a new deep well under the proposed royalty relief is still higher than the expected net cost of a deep sidetrack with no royalty relief in over 90 percent of the reservoir targets drilled to deep depths. For the remaining cases, the differences between the full costs of sidetracks and costs net of royalty relief for new wells is small. So royalty relief only for a new well is generally not large enough to distort investment decisions by reversing the relative economics of a new deep well versus a new deep sidetrack.

To help us evaluate the possible significance of deep sidetracks, we would like responses to the following questions included in comments:

• When and how often is drilling a sidetrack used to explore a new reservoir rather than to supplement an original development or delineation well, and is the situation different by drilling depth?

• How important is sidetracking to a deeper depth in comparison to sidetracking in shallower pay zones, and why?

• Would the proposed relief program distort decisions in favor of more costly new deep wells instead of less expensive deep sidetracks? If so, how serious and/or extensive would this effect be?

If we decide to provide royalty relief for deep sidetracks, we have a range of options for doing so. For example, we could offer the proposed royalty suspension volumes to new deep wells and to a subset of new deep sidetracks that meet certain timing or offset distance considerations. We could offer a lower royalty suspension volume than proposed here to all new wells drilled to a given depth. We could offer one royalty suspension volume for new deep wells and another lower or variable (e.g., based on offset distances) for deep sidetracks.

To help us evaluate these and other options, we would like responses to the following questions included in comments:

• To what extent does the absence of royalty relief for sidetracks adversely affect deep depth drilling and distort the choice between the types of wells drilled?

• If a subset of deep sidetracks were to receive a royalty suspension volume:

—Should we limit the incentive to sidetracks that achieve a minimum offset distance? If so, what is the proper minimum offset distance and why is this offset distance appropriate?

—Should we limit the incentive to a sidetrack from a new well that is drilled after the publication date of this proposed rule? Why?

—Should we limit the incentive to a sidetrack from a deep well as opposed to a shallow well? Why?

—Should a single royalty suspension volume be set based on the relative average costs of sidetracked deep wells in comparison to new deep wells?

• What other elements should we consider in determining the royalty suspension volume if we decide to employ different ones for new deep sidetracks and for new deep wells?

—Should the size of the royalty suspension volume vary with the offset distance of a sidetrack or should there be a single volume for deep sidetracks? Why?

—Does the cost of a sidetrack increase per extra foot drilled relative to that of a straight hole?

—Should the royalty suspension volume for sidetracks apply to only the very deep total depths (18,000 feet TVD SS or deeper)? Why?

• Should sidetracks receive the same, different, or no royalty suspension supplement as new wellbores drilled to very deep total depths (18,000 feet TVD SS or deeper)?

• What size supplement would be effective and efficient in the program for drilling unsuccessful sidetrack wells?

• In addition to the API survey, are there any other publicly available sources that offer data on deep sidetrack drilling costs?

Auction Mechanism Discussion

MMS would like to solicit comments on an alternative mechanism to allocate royalty relief for existing leases. This approach will not be pursued for this rulemaking, but may be pursued for future allocations. MMS would like to solicit comments on the feasibility of this approach, as well as solicit inputs on alternative approaches to make the allocation of royalty relief more efficient. This approach would seek to allocate approximately the same total royalty relief, but would differ in that not all lessees would receive the same relief, with the objective of encouraging greater levels of overall drilling at lower or comparable Federal cost.

Under this alternative, MMS would allocate royalty relief suspension volumes and supplements as soon as practicable after publishing the final rule. Authorized leaseholders, those with leases awarded prior to 2001, would submit to MMS an offer of the volume of royalty relief they would require to undertake deep well drilling. MMS would rank the offers from the least amount of royalty relief to the greatest, taking into consideration the depth of the wells (15,000–18,000 ft or >18,000 ft). MMS would select the best ranked offers according to a process described below. MMS would then renegotiate the terms of existing leases of the selected leaseholders to provide the royalty relief per their individual offers. The remaining offers—those requiring the largest royalty relief—would not be accepted. For any royalty relief awarded, the leaseholder must begin drilling a deep well within a designated time period.

The cutoff for accepting the ranked offers in this approach would be based on the incremental production MMS estimates the relief will produce and the total Federal cost expended. This would include, for example, the total number of wells MMS expects to produce, the volume of royalty relief provided to each well, the expected number of wells that would not be drilled without royalty relief, the number of bids judged to have been offered by authorized lessees who can claim relief from new drilling activities and who actually intend to drill to deep depths, and the likelihood of drilling success. In using those estimates to determine the pool of accepted offers, MMS would seek to allocate approximately the same total royalty relief as the preferred alternative.

The eligibility requirements that MMS would apply to the preferred alternative would also apply under this approach. For example, leaseholders that have already drilled successful deep wells before the proposed rule is published would not be eligible for this program. However, leaseholders who first drill a successful deep well after the proposed rule is published would be eligible to receive royalty relief if their bid for royalty relief was accepted. MMS would ask leaseholders to specify in their offers the depth of wells they would drill, and the volume of royalty relief suspension volume they seek on a successful well. Leaseholders would specify separate royalty relief suspension volumes in their submission, one for 15,000–18,000 ft depth and the other for >18,000 ft depth. Leaseholders can also specify a royalty relief supplement for up to two unsuccessful wells in the >18,000 ft depth. The magnitude of the royalty relief supplement per well should not exceed 5 BCF.

This alternative approach may result in added drilling activity and production for lower or the same Federal forgone royalties compared to the preferred alternative, because it encourages lessees who would drill without relief to accept lower relief amounts than they would receive under a fixed allocation system.

There are some unresolved issues with this approach. MMS would like to specifically solicit comments on the following issues:

(1) What is the risk to the integrity of the auction approach if successful bidders choose not to drill within the specified period and thus inadvertently penalize unsuccessful bidders? What can or should MMS do to minimize this outcome?

(2) What is a reasonable period of time in which to expect operators to commence drilling after their offer is accepted? Is three years too short of a period?

(3) Should MMS accept offers in a single sale at the outset of the program, or allocate the relief in a series of sales held over several years?

(4) How does this approach compare with the preferred alternative in its likelihood of granting relief to those who really need it and those who do not?

(5) What technical considerations arise in ranking the offers and determining the cutoff for the accepted ones?

(6) How much is MMS likely to save and at what cost in terms of drilling delayed or forgone as a result of employing this alternative allocation mechanism?

Procedural Matters

Public Comments Procedures

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

Regulatory Planning and Review (Executive Order 12866)

According to the criteria in Executive Order 12866, this rule is a significant regulatory action for which a Regulatory Analysis has been prepared. The Office of Management and Budget (OMB) has made that determination under Executive Order 12866.

(1) This preferred alternative proposed in this rule will have an economic effect of $100 million or more by reducing consumer expenditures on natural gas by about $280 million each year and may have a slightly adverse effect on other units of government. An economic analysis of this regulatory action was prepared and will be available at *http://www.mms.gov/econ*. This proposed rule reduces royalties for lessees that drill and produce natural gas from deep wells in shallow water areas of the GOM. The royalty suspension volumes offered should increase deep drilling activity on existing leases over the period of the program and make additional resources economic. The royalty suspensions will reduce net Federal royalty collections by about $270 million in net present value.

The royalty relief program for deep gas drilling will have two distinct effects, recovery of some otherwise uneconomic gas resources and accelerated recovery of some marginally economic gas resources. Our data indicate that about 10 to 20 percent of the undiscovered gas resources in the most prospective depths, *i.e.*, 18,000 TVD SS or deeper, could be converted from an unprofitable to profitable state by the incentives provided in this rule. We estimate that those resources are located in approximately 20 to 30 percent of undiscovered gas reservoirs.

We estimate that about one-fourth of the economically explorable gas reservoirs at drilling depths 18,000 feet TVD SS or deeper, would be drilled one to five years sooner if we implement the proposed royalty suspension volumes and royalty suspension supplements. These reservoirs are associated with less than 10 percent of the undiscovered resource. We estimate that the aggregate amount of undiscovered gas resources possibly affected at depths 18,000 feet TVD SS or deeper alone amount to over two TCF. Application of our proposed program to reservoirs in the 15,000 to less than 18,000-foot TVD SS range of drilling depth could affect another one to two TCF of gas. The deep drilling program will affect only a part of these resources in any one year.

(2) This rule will not create any inconsistencies with actions by other agencies because royalty relief is confined to leasing in Federal offshore waters that lie outside the coastal jurisdiction of State and other local agencies. Careful review of the lease sale notices along with stringent leasing policies now in force, ensure that the Federal OCS leasing program, of which royalty relief is only a component, does not conflict with the work of other Federal agencies.

(3) This rule may have a small effect on entitlements, grants, user fees, loan programs, or their recipients. The main effect will be to postpone royalty distributions. MMS distributes about one percent ($40 million) of the OCS revenue it collects annually in the GOM to neighboring States under section 8(g) of the OCSLA. Royalty suspensions from the deep gas program could affect up to five percent of the total production from the GOM in any one year. If deep gas production occurs in the 8(g) zone at the same proportion as elsewhere in the GOM, these State grants could be reduced by $1 to $2 million per year for five to ten years. However, extra production that occurs because of the incentive will also provide extra royalties, mostly after the royalty suspension volumes have been produced. Ultimately, the extra royalties could fully offset the initial drop in both Federal and State royalties. This would occur if our program generates 25 percent more incremental gas resources than we estimated would occur in the most likely scenario.

(4) This rule raises a novel legal or policy issue. The royalty suspension supplement for an unsuccessful deep gas well expands the scope of royalty relief to reward efforts for exploration in frontier well depths whether or not they eventually produce. As explained earlier, we believe this creates a more cost-effective royalty relief program in this very risky environment.

In addition, royalty suspension volumes have been used for several years as an incentive to accelerate exploration and production in deep water. Application to deep gas is a logical extension of that policy. A well-defined program for deep-gas drilling is more administratively efficient than the elaborate case-by-case requirements of the application process for deepwater royalty relief. The focus here is on a very straightforward definition of well depth and circumstances to qualify for royalty relief.

An economic analysis of this regulatory action was developed in accordance with requirements associated with a major rule under executive order and statutory criteria. This analysis describes why market forces alone will not increase deep gas development in the short term, considers a range of possible royalty relief alternatives to serve that need, and analyzes the social benefits and costs and related transfer payments associated with several royalty suspension alternatives. Three options provide the highest level of added production and net social benefits. One, option A, is the level of royalty suspension proposed in this rule—15 BCF for successful wells to 15,000—18,000 feet TVD and 25 BCF of successful wells or 5 BCF for unsuccessful wells to 18,000 feet TVD or deeper. The two others provide a reduced level of royalty suspension. The second, option B, offers 10 BCF for successful wells to 15,000—18,000 feet TVD and 25 BCF of successful wells or 5 BCF for unsuccessful wells to 18,000 feet TVD or deeper. The third, option C, offers 10 BCF for successful wells to 15,000—18,000 feet TVD and 20 BCF of successful wells or 5 BCF for unsuccessful wells to 18,000 feet TVD or deeper. These three options performed much better on several criteria than alternatives which include higher suspension levels as a substitute for royalty relief for unsuccessful drilling.

We ranked alternatives based on estimates of their net social benefits. Net social benefits are the sum of the net gains to producers and consumers associated with the additional production attributable to this rule. These gains are measured as changes in consumer and producer surplus relative to a status quo or baseline amount that would occur in the absence of the incentive. Consumer surplus is the difference between the value consumers place on the additional production and its market value. Producer surplus is the difference between the market price and the cost of additional production (including the cost of drilling unsuccessful wells). Transfer payments, on the other hand, consist primarily of changes resulting from the rule in the amount of Federal royalty payments and domestic expenditures to purchase status quo quantities of gas. This summary reviews the performance of the superior options based on several criteria—added production, forgone royalty, and net social benefits from production that would not have occurred without an incentive for deep gas drilling.

We estimate that option A, the proposed royalty suspension level, would generate a cumulative added production of 2.36 TCF of gas and 0.51 TCFE of condensate over the next 15 years. In contrast, option B would generate added production of 2.15 TCF of gas and 0.46 TCFE of condensate over the same time frame, while option C will generate 1.94 TCF of gas and 0.42 TCFE. Added production consists of production from reservoirs unlikely to be drilled under normal conditions and from a portion of reservoirs only likely to be drilled in the future after information, technology, and costs improve, *i.e.*, accelerated production.

Using assumptions about prices, discount rates, and well flow rates, we estimated the net social benefits to society from increased deep gas production. As discussed above, this primary measure of social welfare effects eliminates the sizeable transfers from producers to consumers associated with reduced prices, and from government to producers in the form of reduced royalty payments. The incremental supply added to domestic stocks as a result of the incentive generates a net gain to society. Under option A, the proposal, we estimate a net social gain of $153 million in present value versus $139 million under option B and $121 million under option C.

Another perspective on the effects of the rule is provided by comparing increased production to forgone royalty-bearing production. We estimate that royalty would be forgone under option A, the proposal, on 2.1 TCF of gas production that would have occurred anyway. That implies a ratio of extra production to foregone royalty bearing production of 1.36 [(2.36 TCF + 0.51 TCFE)/2.1 TCF]. For option B this ratio is 1.50 [(2.15 TCF + 0.46 TCFE)/1.74 TCF], and for option C it is 1.49 [(1.94 TCF + 0.42 TCFE)/1.59 TCF]. Hence, any of the three deep gas incentive options is preferable to no such incentive.

Some of the forgone royalty would be offset by royalty collections on the condensate and on added gas production after the royalty suspensions have been used. Taking those into account and distributing the production over the next 15 years, we estimate a net reduction in present value of royalty receipts of $267 million under the proposal versus $124 million for the second alternative and $114 million for the third alternative. These results suggest that options B and C provide slightly less production effects and somewhat lower net social benefits at more than proportionately lower forgone royalty revenues.

Regulatory Flexibility (RF) Act

Several factors make promulgation of this rule at this time important. U.S. demand for natural gas is expected to rise strongly over the next decade while domestic supplies are dwindling. Imported gas provides only a small share of domestic supplies because of the inherent difficulty and danger of transporting gas. A large and promising source of domestic gas, deep reservoirs on existing OCS leases in the shallow water part of the GOM, has been little explored. This is because the costs and risks of drilling deep reservoirs are high relative to drilling shallow reservoirs on these same leases. Further, these higher costs would rise if much of the extensive infrastructure (platforms and pipelines) developed to support the production of shallow reservoirs gets removed as the shallow reservoirs deplete. That means there is a significant chance these deep resources would never be produced if not encouraged now.

Objectives of, and Legal Basis for, the Proposed Rule

To accelerate and increase drilling into deep reservoirs, this rule proposes to:

(1) Suspend royalty payments for specified volumes of deep production that begins in the 5 years after the rule becomes effective; and

(2) Allow producers to apply designated amounts of royalty suspension supplements to other lease production for deep drilling that fails to encounter producible reserves.

Together, these measures will reduce the royalty costs associated with deep drilling and production below the royalty costs of other production on the same lease.

Title 30 CFR part 203 regulates the reduction of oil and gas royalty under 42 U.S.C. 1337(a)(3). Under section 1337 (a)(3)(B), we may reduce, modify, or eliminate royalties on certain producing or non-producing leases or categories of leases to promote development or increased production or to encourage production of marginal resources, in the GOM west of 87 degrees, 30 minutes west longitude.

Estimate of the Number of Small Entities to Which the Proposed Rule Will Apply

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

• Annual revenues of $6 million or less for exploration service and field service companies.

• Fewer than 500 employees for drilling companies and for companies that extract oil, gas, or natural gas liquids.

Under the North American Industry Classification System Code 211111, Crude Petroleum and Natural Gas Extraction, MMS estimates that a total of 1,380 firms drill oil and gas wells onshore and offshore. Of these, approximately 130 companies are active offshore in the GOM. Merger and acquisition activity is constantly adjusting the exact number of operators. Publicly available data (from Compustat, Standard and Poor's, McGraw-Hill, and from Dunn & Bradstreet via Hoovers' sites on the internet) indicate that 39 (30 percent) of these companies active in offshore activities qualify as large firms according to SBA criteria, leaving up to 91 (70 percent) companies that qualify as small firms with fewer than 500 employees. Further breakdown of the small entity operators indicate that 28 percent have between 100 and 500 employees, 53 percent have between 1 and 100 employees, and the rest have no employees as they are fully staffed by contractors. As explained in the next section, compliance costs are minimal for small as well as large entities.

Reporting, Recordkeeping and Other Compliance Requirements

The proposed rule requires reporting within the meaning of the Paperwork Reduction Act in four situations. These situations are:

(1) Notify the Production and Development Division of MMS in the GOM region (MMS–PD) of intent to commence drilling a deep well;

(2) Notify MMS–PD that production has commenced from the deep well and request confirmation of the size of royalty suspension volume;

(3) Provide MMS–PD with data from the deep well to confirm that the well drilled was an unsuccessful certified well and request supplement; and

(4) Notify MMS–PD of a decision to exercise an option to replace the deep gas royalty suspension terms in the lease document with the terms in the proposed rule.

The frequency of reporting is on occasion. Responses are voluntary but are required to obtain or retain a benefit. We will protect information considered proprietary according to 30 CFR 203.63(b) and 30 CFR 250.196.

Because this program is administered on a categorical rather than a lease-by-lease basis, minimal administrative time and cost is needed to qualify for royalty relief. The notifications in items (1) and (2) above only entail sending a letter affirming that an action which is a normal part of business operations has occurred. Item (3) involves sharing data from well logs and seismic surveys that the company would develop even in the absence of this rule as a normal part of its exploration business. The notification in item (4) involves making a business decision about which of two alternative incentives best fit the prospects faced by the individual lease. The professional skills involved include those normally used in the operation of all OCS leases—geologists, geophysicists, engineers, and economists. Since no special analysis or independent review would be necessary to accomplish these compliance activities, we see very little burden on normal operations of either small or large companies. Beyond the paperwork notifications, there are no other compliance costs associated with this proposed rule.

The following passages and table are derived from our Paperwork Reduction Analysis. The proposed rule would increase the total paperwork hour burden of the 30 CFR part 203 regulations by 361 hours annually, spread across the entire industry. Based on a cost factor of $50 per hour, the burden of the new paperwork requirements would be $18,050 for the entire industry. This cost pales in comparison to the $10 to $20 million that it costs to drill a single well on the OCS to the deep depths covered by this proposed rule. As explained in the detailed economic analysis of this regulation, we estimate profits to both large and small entities will increase an average of over $33 million per year. The small business proportional share would be $23 million. So, even if small businesses were to bear 100 percent of this compliance costs, it would represent less than 1/10th of one percent of the average annual gross benefits obtained by small business in the form of their proportional share of added industry profits. The last sub-section of this Regulatory Flexibility section mentions two reasons, *i.e.*, risk sharing and location advantages, to think that small OCS entities could get a disproportionate share of the large benefits of this rule, so small entities could get significant positive net benefits from this rule as well. Furthermore, choosing to engage in this program, and hence incurring the nominal compliance cost, is voluntary. Non-participation is not detrimental, since companies that choose not to participate are no worse off than they would be in the absence of the rule.

Except for the row associated with § 48(b), these annual measures of burden costs cover the 5 to 6 years in which the incentive would be effective. The switch option of § 48(b) is only available for 6 months after the rule becomes effective. We assume the small business share of compliance costs is proportional to the maximum small business presence in offshore activities, *i.e.*, 70 percent. This means that small business would incur up to 253 burden hours in year 1 and 204 burden hours in years 2 through 6.

INDUSTRY BURDEN BREAKDOWN

30 CFR 203 section	Reporting requirement	Hour burden	Annual number	Annual burden hours
43(a), 46(a)	Notify MMS of intent to commence drilling	1	[1] 89	89
43(b)(1)(2)	Notify MMS that production has commenced and request confirmation of the size of royalty suspension volume.	2	[1] 25	50
46(b)(1)(2)	Provide data from well to confirm and attest well drilled was an unsuccessful certified well and request supplement.	8	[2] 19	152
48(b)	Notify MMS of decision to exercise option to replace one set of deep gas royalty suspension terms for another set of such terms.	2	[1] 35	70
Total reporting burden—1 year			[3] 168	361
Total reporting burden—2–6 years			[3] 133	291

[1] Notices.
[2] Submissions
[3] Responses.

Federal Rules That May Duplicate, Overlap or Conflict With the Proposed Rule

We are not aware of any Federal rules that conflict with the proposed rule. Two other kinds of royalty relief apply to OCS leases, but do not overlap this proposed rule. Deep water royalty relief has been granted to leases in water at least 200 meters deep in the GOM since 1996, but no leases covered by this proposed rule are eligible for deep water royalty relief. Also, any OCS lease may apply for royalty reduction when it nears the end of its economic life, but this form of relief is only relevant to mature production on a lease, not to development of new reservoirs covered by this proposed rule.

A different royalty relief incentive for deep gas drilling has been included for newly issued leases in the five OCS lease sales held since the beginning of 2001. This incentive is not available to older leases issued before 2001, so they do not overlap the main set of leases targeted by this rule. However, a provision of this proposed rule allows newly issued leases a one-time option to switch to the incentives in this proposed rule. This switching provision is included to be fair and is voluntary. Lessees paid a premium in their bid for the new leases because their lease terms included deep gas royalty relief. Lessees of older leases had no expectation of royalty relief so their lease bids included no such premium. Allowing new lessees to switch lets those who paid for deep gas royalty relief in their bonus bid choose the more favorable of the two incentives. This switching provision also optimizes the incentive effects of the proposed rule because it will promote more deep gas development by those lessees that choose to switch. Finally, switching enables administrative simplifications when lessees on the same unit choose the same incentive terms. We estimate the aggregate small entity share of the one-time paperwork cost to be proportional to their presence in offshore activity, *i.e.*, 70 percent of $3500, or about $2500.

The proposed rule slightly overlaps two regulations applicable to OCS leases. OCS lessees must submit an application for permit to drill (30 CFR 250.414) to the local MMS district office for review, processing, and eventual entry into an agency-wide data base. This application is a more involved submission than the letter required in the proposed rule notifying MMS-PD of intent to commence drilling. We propose to require the simplified but duplicate version of this application because it is a minimal action that provides important lead time for coordinating other MMS actions that may concern the lease. For example, a potential royalty suspension requires adjustment if the subject lease participates in our royalty-in-kind program. OCS lessees must also notify the local MMS district office when production begins on the lease (30 CFR 250.180). If the deep well is not the first production on the lease, the notice required under this rule would not be duplicative. It, also, would be vital to help avoid confusion when a lease has both royalty-bearing and now royalty-free production. Most of the older leases in shallow water have to be in production already as a condition of holding their lease. The proposed notification would be redundant only when the deep well is the first production on the lease. We believe it is simply easier to set this minimal notice burden on the start of all deep production than to create separate notice rules depending on whether a lease has prior production or not. Even when redundant, the notice serves as a useful check on a long-standing routine report.

Significant Alternatives to the Proposed Rule

The Regulatory Flexibility Act requires the agency to consider alternatives to the proposed rule. The paperwork costs are only 1/10th of 1 percent of these benefits and are the minimal necessary to allow the monitoring essential to a consistent administration of a categorical relief program across all participants. The alternative of a case-by-case relief program, where each operator would apply to participate would enormously increase the paperwork burden and associated costs for all participating lessees, both small and large entities. While case-by-case review might reduce forgone royalty, it would add uncertainty about approval and thus discourage new drilling relative to the categorical program. Also, an application process would discourage participation especially by small operators who are unlikely to have the staff needed to assemble and defend an appropriate application.

Alternative forms of the categorical deep gas incentive we considered included: (1) Reduction of royalty rates for production emerging from new deep wells, (2) suspending royalty for a fixed value rather than a volume of new deep production, (3) a royalty suspension volume only for successful deep wells, (4) different royalty suspension volumes, and (5) no incentives. These alternatives are fully discussed in the detailed economic analysis of this regulation and will be available at www.mms.gov/econ. The administrative costs are the same for all the categorical incentive alternatives. Only the benefits are different. The alternative we chose results in the largest benefit to producers and to the small entity share of producers.

A summary discussion of the alternatives is included in the section titled ‘‘Details of Proposed Royalty Relief for Deep Gas Production’’ of this preamble. We chose the incentive form that combines a royalty suspension volume for successful deep gas wells and a royalty suspension supplement for unsuccessful deep wells for three reasons:

(1) It is large enough to generate substantial deep drilling activity;

(2) It is the most cost-effective incentive structure for the Government because it does not waste as much relief as alternatives on prospects that will be drilled anyway; and

(3) It concentrates most of the incentive on the very deep (18,000 feet or deeper subsurface) zones where we believe most of the undiscovered potential is to be found.

A more detailed explanation of these findings is contained in the economic analysis of this regulatory action. Additionally, this proposed incentive structure also may especially benefit small operators more than the alternative categorical incentive structures mentioned above.

The royalty suspension supplement feature improves the ability of small companies with limited drilling programs to spread their risk. Success on one or two of many deep wells that a large operator drills in a given period can pay the costs incurred for the unsuccessful wells. Small operators may be able to drill only one or two deep wells in a given period. The royalty suspension supplement can reduce the net cost of unsuccessful deep wells immediately, so the small operator does not necessarily have to wait for a deep well success in a later period to offset at least some unsuccessful exploration costs. This is a feature not found in any of the alternative categorical incentive structures which confer royalty relief only on successful wells.

Because of the risk, high cost, and technical complexity, we expect most lessees/operators involved in exploration and development in deep drilling depths of the GOM to be large companies. However, the location eligible for deep gas royalty relief is in shallow water, where we find relatively more small operators compared to those found in deep water. Thus, relatively more of those OCS operators who will benefit from the deep gas incentive in this rule may be in the small business category than those who benefit from deep water royalty relief.

For these reasons we believe this proposed rule is likely to provide at least a proportionate share of its benefits to small businesses. Nevertheless, MMS seeks to understand and address unforeseen impacts of this proposed rule on small businesses. Please provide comment on any or all provision in the proposed rule with respect to its effect on small entities. In particular, pay specific attention to the following sections of the proposed rule and assumptions discussed above:

- The overlapping notice of intent to commence drilling, §§ 203.43(a) and 203.46(a);
- The possibly overlapping notice that deep production has commenced § 203.43(b);
- The requirement to provide seismic and well test information to confirm drilling an unsuccessful well § 203.46(b);

• The one-time notice of a switch to the proposed deep gas incentive terms § 203.48(b); and

• Our assumptions that:

(1) Small entities are more prevalent in the shallow water than the deep water GOM;

(2) The risk, cost, and technical complexity of deep drilling is more like that found in deep water development than in traditional shallow water development; and

(3) The royalty suspension supplement tends to be more valuable to small entities with fewer deep drilling opportunities than large entities that have more deep drilling opportunities.

Small Business Regulatory Enforcement Fairness Act (SBREFA)

This rule is a major rule under 5 U.S.C. 804(2), the SBREFA. This rule:

(1) Does have an annual effect on the economy of $100 million or more. This rule introduces a royalty relief program for deep gas that will save consumers $200 million annually for about a decade. Based on the EIA price projections, the reduction in royalty collected by the Federal government under the revised rulemaking would exceed the $100 million per year threshold in five out of 16 years in which meaningful amounts of program related production are generated. The benefits of the rule on the economy more than offset the royalty losses. A comparison of two types of production provides a proxy measure of this net social benefit. We estimate the magnitude of new gas production that ultimately occurs because of the incentive in the rule is about 1.4 times the size of gas production on which the government forgoes royalty. The government only forgoes royalty on production that would have occurred anyway without the incentive. Moreover, consumers of natural gas will benefit from additional domestic gas supplies and have lower market prices.

More lessees may take advantage of the proposed new deep gas royalty relief provisions over the next few years than have ever applied for end-of-life or deepwater royalty relief. However, the incremental drilling and production induced by this royalty relief will be small relative to total gas drilling and production in the GOM. The main thrust of the initiative is to increase and help accelerate new gas production to promote timely production otherwise inhibited. Even a small moderation of prices due to added deep gas production would result in a significant savings in gas expenditures and dampen natural gas prices in the market. Further, the proposed rule would impose no costs on any local or private entity, but may initially impose some small costs ($1 to $2 million per year) on Gulf coast States in the form of reduced payments under Section 8(g) of the OCSLA. However, production that otherwise would not occur will result from these incentives. That production will produce extra royalty payments, mostly after the royalty suspension volumes have been produced. Participation in the program by lessees is voluntary.

We consider the key adverse economic effect of this program with regard to the $100 million dollar annual benchmark to be forgone Federal royalties on deep gas production that would have been generated without this program. Since lower royalties mean more taxable income to companies, we measure the effect on forgone Federal revenues net of tax increases, assuming a 25 percent tax rate. Note that this is a transfer payment so that the government loss is also an operator gain from pursuing a socially desirable activity—deep gas production.

We forecast that without the proposed deep gas royalty relief program, 37 wells would be drilled annually to depths of 15,000 to 18,000 feet TVD SS and 11 wells to drilling depths below 18,000 feet TVD SS. Based on trends in drilling deep depths during the past 10 years in shallow water, we expect 12 successful wells in the 15,000 to 18,000 feet TVD SS drilling depth and 3 successful wells at deep drilling depths below 18,000 feet TVD SS without the incentive. We assume all these new successful deep wells are on different leases. With the incentive, we estimate there would be 35 wells drilled to depths below 18,000 feet TVD SS, of which 28 would be unsuccessful, and 19 of them on leases having other production to which the royalty suspension supplement could be used.

Annually over the 2003 through 2009 period, the absence of our deep gas royalty relief program could thereby save the government about 350 BCF in new royalty suspension volumes (12 * 15 + 3 * 25 + 19 * 5) awarded for drilling activities that would have occurred anyway. These savings may decline before the program ends in about 2009 because of the availability of less prospective reservoirs in later years of the program. Further, in any one year, only about 20 to 25 percent of the accrued amount of royalty suspension volumes could actually be used.

Offsetting most of these initial royalty losses are the extra royalties in later years on production beyond the royalty suspension volume from additional reserves discovered because of the incentive. Along with the incremental 24 wells (35–11) annually to drilling depths below 18,000 feet TVD SS, we expect 17 incremental wells (54–37) would be drilled annually to depths of 15,000 to 18,000 feet TVD SS. We estimate these incremental wells ultimately will lead to production of about 2.3 TCF, of which 0.7 would be royalty-free and 1.6 TCF would be royalty-bearing. We anticipate that the royalties on this 1.6 TCF of production will begin in about 2010 and continue until about 2025. Further offsetting benefit also comes from extra profits from production that would otherwise not occur.

A detailed economic analysis of this regulatory action was prepared and will be available at *http://www.mms.gov/econ*. This economic analysis explains our monetary calculations.

(2) Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions. The deep gas incentive should materially moderate expected gas prices by adding to the overall supply.

(3) Does not have significant adverse effects on competition, employment, investment, innovation, or the ability of United States-based enterprises to compete with foreign-based enterprises. Companies eligible for the proposed deep gas royalty relief should produce more natural gas and earn more income, while encountering no negative effects.

Paperwork Reduction Act (PRA) of 1995

The proposed rule requires information collection (IC), and an IC request (form OMB 83–I) has been submitted to OMB for review and approval under section 3507(d) of the PRA. The title of the collection of information is ''Proposed Rulemaking-30 CFR 203, Deep Gas Provisions.'' Respondents include approximately 130 Federal OCS oil and gas lessees. The frequency of reporting is on occasion. Responses are required to obtain or retain a benefit. The IC does not include questions of a sensitive nature. We will protect information considered proprietary according to 30 CFR 203.63(b) and 30 CFR 250.196.

OMB approved the information collection requirements in the current 30 CFR 203 regulations under control number 1010–0071, with a current expiration date of September 30, 2003. The following table lists the proposed new IC requirements and respective burdens. The proposed rule would increase the total paperwork hour burden of the 30 CFR part 203 regulations by 361 hours. Based on a cost factor of $50 per hour, the hour burden of the new paperwork requirements would be $18,050.

BURDEN BREAKDOWN

30 CFR 203 section	Reporting requirement	Hour burden	Annual number	Annual burden hours
43(a), 46(a)	Notify MMS of intent to commence drilling	1	[1] 89	89
43(b)(1)(2)	Notify MMS that production has commenced and request confirmation of the size of royalty suspension volume.	2	25	50
46(b)(1)(2)	Provide data from well to confirm and attest well drilled was an unsuccessful certified well and request supplement.	8	[2] 19	152
48(b)	Notify MMS of decision to exercise option to replace one set of deep gas royalty suspension terms for another set of such terms.	2	35	70
Total reporting burden			[3] 168	361

[1] Notices. [2] Submissions. [3] Responses.

MMS would use the information collected to determine whether a lessee is qualified to receive the relief offered in this proposed program.

As part of our continuing effort to reduce paperwork and respondent burdens, MMS invites the public and other Federal agencies to comment on any aspect of the reporting burden in the proposed rule.

(1) We specifically solicit comments on the following questions:

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

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

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

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

(2) In addition, the PRA requires agencies to estimate the total annual reporting and recordkeeping ''non-hour'' cost burden resulting from the collection of information. We have not identified any and solicit your comments on this item. For reporting and recordkeeping only, your response should split the cost estimate into two components: (a) The 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. Generally, your estimates should not include equipment or services purchased: before October 1, 1995; to comply with requirements not associated with the information collection; for reasons other than to provide information or keep records for the Government; or as part of customary and usual business or private practice.

You may submit your comments directly to the Office of Information and Regulatory Affairs, OMB. Please send a copy of your comments to MMS so that we can summarize all written comments and address them in the final rule preamble. Refer to the ''Addresses'' section for mailing instructions. OMB is required to make its decision on the information collection aspects of this proposed rule between 30 to 60 days after publication in the **Federal Register**. Therefore, a comment to OMB is best assured of having its full effect if OMB receives it by April 25, 2003. This does not affect the deadline for the public to comment to MMS on the proposed regulations.

The PRA provides that an agency may not conduct or sponsor a collection of information unless it displays a currently valid OMB control number. Until OMB approves the collection of information and assigns an OMB control number, you are not obligated to respond.

Federalism (Executive Order 13132)

According to Executive Order 13132, this rule does not have meaningful Federalism implications. As noted above it may initially impose some small costs ($1 to $2 million a year) on Gulf coast States in the form of reduced payments under Section 8g of the OCSLA. However, additional resources discovered under this incentive will make up for these initial reductions from production that otherwise would not occur. Largely after the royalty suspension volumes have been produced, extra royalties for Federal and Gulf coast States will result from this extra production. Also, the added economic activity in those States associated with new deep drilling will generate new tax revenues. Therefore, a Federalism assessment is not required because the proposed rule would not have a direct or substantive effect on the relationship between the Federal and State Governments, nor does it impose responsibilities or costs on States or localities.

Takings Implication Assessment (Executive Order 12630)

According to Executive Order 12630, the rule does not have significant Takings implications. A Takings Implication Assessment is not required. This rule has no Takings effect, because it only specifies circumstances under which royalty payments to the Federal Government by OCS lessees might be reduced. The lessee of such a lease would be better off financially under this rule.

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

This rule is a significant rule and is subject to review by OMB under Executive Order 12866. This rule does not have a significant adverse effect on energy supply, distribution, or use. This rule increases and accelerates the production of gas from deep wells on the OCS shelf by providing for a royalty suspension volume for successful deep production and a royalty suspension supplement for unsuccessful deep drilling efforts, so it has a positive effect on energy supply based on our regulatory analysis.

Unfunded Mandates Reform Act (UMRA) of 1995

This proposed rule does not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than $100 million per year. The proposed rule does not have any Federal mandates nor does the proposed rule have a significant or unique effect on State, local, or tribal governments or the private sector. A statement containing the information required by the UMRA (2 U.S.C. 1531 *et seq.*) is not required.

Civil Justice Reform (Executive Order 12988)

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

National Environmental Policy Act (NEPA) of 1969

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

Government-to-Government Relationship with Tribes

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

Clarity of this Regulation

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

(1) Are the requirements in the rule clearly stated?

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

(3) Is the description of the rule in the ''Supplementary Information'' section of this preamble helpful in understanding the rule? What else can we do to make the rule easier to understand?

Send a copy of any comments that concern how we could make this rule easier to understand to: Office of Regulatory Affairs, Department of the Interior, Room 7229, 1849 C Street, NW., Washington, DC 20240. You may also e-mail the comments to this address: *Exsec@ios.doi.gov.*

List of Subjects in 30 CFR Parts 203

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

Dated: March 20, 2003.

Rebecca W. Watson,

Assistant Secretary, Land and Minerals Management.

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

PART 203—RELIEF OR REDUCTION IN ROYALTY RATES

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

Authority: 25 U.S.C. 396 *et seq.*; 25 U.S.C. 396a *et seq.*; 25 U.S.C. 2101 *et seq.*; 30 U.S.C. 181 *et seq.*; 30 U.S.C. 351 *et seq;* 30 U.S.C. 1001 *et seq;* 30 U.S.C. 1701 *et seq;* 31 U.S.C. 9701 *et seq;* 43 U.S.C. 1301 *et seq;* 43 U.S.C. 1331 *et seq;* and 43 U.S.C. 1801 *et seq.*

2. Section 203.0 is amended by adding definitions for ''deep well'', ''new well,'' ''participating area'', ''reservoir'', ''royalty suspension supplement,'' ''successful qualified deep well,'' and ''unsuccessful certified well'' in alphabetical order to read as follows:

§ 203.0 What definitions apply to this part?

* * * * *

Deep well means either a well drilled and completed with a perforated interval, the top of which is at least 15,000 feet true vertical depth below the datum at mean sea level (TVD SS), or a well drilled but not completed to a target reservoir deeper than 18,000 feet TVD SS.

* * * * *

New well means a well that results from drilling that does not utilize an existing wellbore.

* * * * *

Participating area means that part of the unit area that is reasonably proven by drilling and completion of producible wells, geological and geophysical information, and engineering data to be capable of producing hydrocarbons in paying quantities.

* * * * *

Reservoir means an underground accumulation of oil or natural gas or both characterized by a single pressure system and segregated from other such accumulations.

* * * * *

Royalty suspension supplement means a royalty suspension volume generated from drilling an unsuccessful certified well and applied to royalties due on future royalty-bearing natural gas and oil production on, or allocated to, the same lease.

* * * * *

Successful qualified deep well means a new deep well completed on your lease:

(1) That begins drilling after March 26, 2003, and

(2) That begins producing natural gas, including gas associated with oil production before [DATE THAT IS FIVE YEARS AFTER THE EFFECTIVE DATE OF THE FINAL RULE].

* * * * *

Unsuccessful certified well means a new well drilled on your lease:

(1) Beginning after March 26, 2003;

(2) Beginning before [DATE THAT IS FIVE YEARS AFTER THE EFFECTIVE DATE OF THE FINAL RULE];

(3) Beginning before your lease produces from a successful qualified deep well;

(4) To a depth of at least 18,000 feet true vertical depth below the datum at mean sea level (TVD SS);

(5) That targeted a reservoir identified from seismic and related data deeper than 18,000 feet TVD SS; and

(6) That fails to meet the producibility requirements of 30 CFR Part 250, subpart A, and does not produce, or that MMS agrees is not commercially producible. (Any well producing from a reservoir 15,000 feet TVD SS or deeper is deemed a successful well, though not necessarily a successful qualified deep well).

* * * * *

3. A new undesignated heading and new §§ 203.40 through 203.48 are added to Subpart B to read as follows:

Royalty Relief for Drilling Deep Gas Wells

§ 203.40 Which leases are eligible for royalty relief as a result of drilling deep wells?

Your lease may receive a royalty suspension volume under §§ 203.41 through 203.43 and may receive a royalty suspension supplement under §§ 203.44 through 203.46 if it:

(a) Was issued in an OCS lease sale held before January 1, 2001, or in a lease sale held on or after that date and the lessee has exercised the option under § 203.48;

(b) Is located in the Gulf of Mexico, wholly west of 87 degrees, 30 minutes West longitude entirely in water less than 200 meters deep; and

(c) Has not produced gas or oil from a deep well that commenced drilling before March 26, 2003. Production before that date from a deep well on another lease on your unit does not make your lease ineligible for royalty relief.

§ 203.41 If I drill a successful qualified deep well, what royalty relief could I receive?

(a) Subject to the administrative requirements of § 203.43 and the price conditions in § 203.47, we will suspend royalties for the produced gas volumes, as reported in accordance with 30 CFR 216.53 (Oil and Gas Operations Report, Part A or OGOR–A), shown in the following table (in billions of cubic feet or BCF):

If you have a successful qualified deep well . . .	Then, we suspend royalties on this volume of deep gas production from or allocated to your lease as prescribed in this section and § 203.42:
(1) From 15,000 to less than 18,000 feet TVD SS.	15 BCF
(2) 18,000 feet TVD SS or deeper.	25 BCF

(b)(1) The royalty suspension volume determined under paragraph (a) for the first successful qualified deep well on your lease establishes the total royalty suspension volume available for that lease. You will not receive an additional royalty suspension volume if you drill more successful qualified deep wells on your lease or if you later drill and complete a deeper well that would have qualified for a higher royalty suspension volume. For example, if you drill a successful qualified deep well to 16,000 feet TVD SS and later drill a second successful qualified deep well on the lease to 19,000 feet TVD SS, your total royalty suspension volume is limited to 15 BCF. If your lease is within an MMS-approved unit, *see* subparagraph (b)(3) of this section.

(2) After you receive a royalty suspension volume for your first successful qualified deep well, if you later begin production from another successful qualified deep well on the lease, you must notify MMS of that production under § 203.43.

(3) This paragraph applies if your lease is within an MMS-approved unit.

(i) If the first successful qualified deep well on your lease is a well within a unit participating area, 100 percent of the royalty suspension volume available for that well under paragraph (b)(1) of this section applies only to your allocated share of production from that well. No other lease in the unit is entitled to any of the royalty suspension volume under this section or § 203.42, even though another lessee may be entitled to a share of the production from the successful qualified deep well on your lease. Your royalty suspension volume for the lease will not increase if your lease is entitled to an allocated share of production under the unit agreement from another deep well either on your lease or another lease in the unit.

(ii) If the first successful qualified deep well located on your lease was not a unit well, and if your lease is entitled to an allocated share of production under an MMS-approved unit agreement from another deep well within the unit participating area either on your lease or on another lease, that allocated share of production will not increase the volume of royalty suspension you qualify for under this section based on the first successful qualified deep well on your lease.

(iii) If you do not have a successful qualified deep well located on your lease, then you are not entitled to any royalty suspension volume for production allocated to your lease under the unit agreement from a successful qualified deep well on another lease in the unit.

(c) Any royalty relief allowed under paragraph (a) of this section is in addition to any royalty suspension supplement for your lease under § 203.44 that results from a different wellbore.

(d) You must pay minimum royalties in accordance with your lease terms notwithstanding any royalty suspension volumes allowed under paragraph (a) of this section.

§ 203.42 To which production do I apply the royalty suspension volume from drilling a successful qualified deep well on my lease?

(a) This paragraph applies to any lease that is not within an MMS-approved unit. Subject to the requirements of §§ 203.40, 203.41, 203.43, 203.44, and 203.47, beginning the day that you provide MMS the notice required under § 203.43, you must apply the royalty suspension volume to production from all successful qualified deep wells on your lease for which you have given notice. Apply the royalty suspension volume applicable to your lease to that production each month until you use all of your royalty suspension volume.

(b) This paragraph applies to any lease all or part of which is within an MMS-approved unit and that has at least one successful qualified deep well located on the lease. Subject to the requirements of §§ 203.40, 203.41, 203.43, 203.44, and 203.47, beginning the day that you provide MMS the notice required under § 203.43, you must apply the royalty suspension volume to your share of production from all successful qualified deep wells on your lease for which you have given notice, and to production volumes allocated to your lease from deep wells on other unit leases drilled after March 26 2003. Apply the royalty suspension volume applicable to your lease to that production each month until you use all of your royalty suspension volume.

(c) Unused royalty suspension volume transfers to a successor lessee and expires with the lease.

(d) You may not apply the royalty suspension volume allowed under § 203.41;

(1) To production from a deep well drilled before March 26 2003;

(2) To production from wells less than 15,000 feet TVD SS;

(3) To deep production from any other lease, except as provided in paragraph (b) of this section.

(e) You must begin paying royalties when the cumulative royalty-free production of gas from or allocated to your lease reaches the applicable royalty suspension volume allowed under § 203.41. For the month in which cumulative production reaches this royalty suspension volume, you owe royalties on the portion of gas production that exceeds the royalty suspension volume remaining at the beginning of that month.

(f) All liquid hydrocarbon volumes are subject to royalty. This includes condensate recovered at separation facilities without processing. If you sell your gas before it is processed, the royalty suspension volumes apply to the gas production reported on the OGOR–A. If your gas is processed before you sell it, the royalty suspension volumes apply only to residue gas generated after processing and not to any natural gas liquids.

§ 203.43 What administrative steps must I take to use the royalty suspension volume?

(a) You must provide written notification to the MMS Regional Supervisor for Production and Development of your intent to commence drilling operations on deep wells; and

(b) Within 30 days of commencement of production that qualifies for royalty suspension, you must:

(1) Notify the MMS Regional Supervisor for Production and Development that production has commenced; and

(2) Request confirmation of the size of the royalty suspension volume that applies to your lease.

(c) You must meet any special production measuring requirements that the Regional Supervisor for Production and Development has determined are necessary under 30 CFR 250, subpart L.

(d) If you commenced drilling a successful qualified deep well after March 26, 2003, and produced it before [EFFECTIVE DATE OF THE FINAL RULE], you must provide the information required by paragraph (b) of this section on or after [EFFECTIVE DATE OF THE FINAL RULE] and no later than [DATE 30 DAYS AFTER THE EFECTIVE DATE OF THE FINAL RULE].

§ 203.44 If I drill an unsuccessful certified well, what royalty relief could I receive?

(a) If you drill an unsuccessful certified well, and satisfy the administrative requirements of § 203.46, you will receive a royalty suspension supplement of five BCF for your lease, to be applied to subsequent production of gas and oil, as reported in accordance with 30 CFR 216.53 (OGOR–A), on or allocated to your lease as provided in § 203.45. The conversion from oil to gas for using the royalty suspension supplement is specified in § 203.73.

(b) You may receive royalty suspension supplements for up to two unsuccessful certified wells per lease. You may not receive more than one royalty suspension supplement from a single wellbore.

(c)(1) If the same wellbore used to qualify for a royalty suspension supplement later produces from a perforated interval the top of which is 15,000 feet TVD SS or deeper no later than [DATE FIVE YEARS AFTER THE EFECTIVE DATE OF THE FINAL RULE], it will become a successful qualified deep well. If the completion of this successful qualified deep well is on your lease, then you must subtract that portion of the royalty suspension supplement that has been applied to other production from the lease from the royalty suspension volume remaining for the lease. The difference represents the maximum royalty suspension volume for which you are eligible on the lease. If the completion of this successful qualified deep well is on another lease, then the royalty suspension volume earned by this other lease must be reduced by the full amount of the royalty suspension supplement applied on your lease. You may not use any remaining unused portion of the royalty suspension supplement earned for that wellbore.

(2) Notwithstanding any other provision of this part, the total amount of royalty relief earned from or applied to production from a single wellbore that originally qualified as an unsuccessful certified well, but that later produces, cannot exceed 25 BCF.

(d) You must pay minimum royalties in accordance with your lease terms notwithstanding any royalty suspension supplements under this section.

§ 203.45 To which production do I apply the royalty suspension supplements from drilling one or two unsuccessful certified wells on my lease?

(a) Subject to the requirements of §§ 203.40, 203.42, 203.44, and 203.47 and beginning the first day of the month that you file the data and request under § 203.46, you must apply royalty suspension supplements stipulated in § 203.44 to production from, or allocated under an approved unit agreement to, the lease that was the target of your drilling, without restriction on the drilling depth of the well producing the gas or oil.

(b) If you have a royalty suspension volume for the lease under § 203.41, you must exhaust the royalty suspension volume before applying any unused royalty suspension supplement to deep gas production.

(c) If you have no production on which to apply the royalty suspension supplement allowed under § 203.44 when it is earned, your royalty suspension supplement applies to the earliest subsequent production on your lease. Unused royalty suspension supplements transfer to a successor lessee and expire with the lease.

(d) You may not apply the royalty suspension supplement allowed under § 203.44 to production from any other lease, except for production allocated to your lease from an approved unit agreement. If the unsuccessful certified well is on a lease subject to an MMS-approved unit agreement, the lessees of other leases in the unit may not use any portion of your royalty suspension supplement.

(e) You must begin or resume paying royalties when cumulative oil and gas production from or allocated to your lease (excluding any deep gas produced subject to a royalty suspension volume allowed under § 203.41) reaches the applicable royalty suspension supplement. For the month in which the cumulative production reaches this royalty suspension supplement, you owe royalties on the portion of gas or oil production that exceeds the amount of the royalty suspension supplement remaining at the beginning of that month.

§ 203.46 What administrative steps must I take to obtain and use the royalty suspension supplement?

(a) Before a deep well targeted to a reservoir on your lease commences drilling, you must notify, in writing, the MMS Regional Supervisor for Production and Development of your intent to begin drilling operations; and

(b) After drilling the well you must:

(1) Provide MMS with data, including any well test data, that allows MMS to confirm that you drilled an unsuccessful certified well as defined under § 203.0. You must submit this data within 60 days after reaching the Total Depth (TD) in your well to be eligible for the royalty suspension supplement under § 203.45; and

(2) Request confirmation that the royalty suspension supplement applies to your lease.

(c) If you commenced drilling an unsuccessful certified well after March 26, 2003, and finished it before [EFFECTIVE DATE OF THE FINAL RULE], you must provide the information required by paragraph (b) on or after [EFFECTIVE DATE OF THE FINAL RULE] and no later than [DATE 60 DAYS AFTER THE EFECTIVE DATE OF THE FINAL RULE].

§ 203.47 Do I keep royalty relief if prices rise significantly?

(a) You must pay royalties on all gas and oil production for which royalty suspension otherwise would be allowed under §§ 203.40 through 203.46 in any calendar year when the average NYMEX natural gas price exceeds the threshold of $5 per million British thermal units (Btu), adjusted annually from year 2000 for inflation. The threshold price is adjusted by the percentage that the implicit price deflator for the gross domestic product changed during the preceding calendar year.

(b) You must pay any royalty due under this section, plus late payment interest under 30 CFR 218.54, no later than 90 days after the end of the calendar year for which you owe royalty.

(c) Production volumes on which you must pay royalty under this section count as part of your royalty suspension volume and royalty suspension supplements.

§ 203.48 May I substitute the deep gas drilling provisions in § 203.0 and §§ 203.40 through 203.47 for the deep gas royalty relief provided in my lease terms?

(a) You may exercise an option to replace the applicable lease terms for relief related to deep gas drilling with those in § 203.0 and §§ 203.40 through 203.47 if you have a lease issued:

(1) From a lease sale held after January 1, 2001, and before [EFFECTIVE DATE OF THE FINAL RULE]; and

(2) Wholly west of 87 degrees, 30 minutes West longitude in the Gulf of

Mexico entirely in water less than 200 meters deep, with royalty relief provisions for deep gas drilling.

(b) You may exercise this option by notifying the MMS Regional Supervisor for Production and Development of your decision before [DATE 180 DAYS AFTER THE EFFECTIVE DATE OF THE FINAL RULE] and specifying the lease and block number.

(c) Once the option is exercised, you must meet all the activity and administrative requirements pertaining to royalty relief for leases eligible for deep gas royalty relief that were issued in an OCS lease sale held before January 1, 2001.

(d) Exercising the option under paragraph (a) of this section is irrevocable. If you do not exercise this option, your original lease terms apply.

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