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Minerals Management Service

30 CFR Parts 218, 256, and 260
Outer Continental Shelf Oil and Gas Leasing; Final Rule
Outer Continental Shelf, Central Gulf of Mexico, Oil and Gas Lease Sale 178, Part 1; Notice

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Parts 218, 256, and 260

RIN 1010–AC–69

Outer Continental Shelf Oil and Gas Leasing

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: This bidding rule establishes the leasing incentive framework we will use to issue Outer Continental Shelf (OCS) leases after November 2000. It also presents a plain-language revision of the existing rules for bidding systems and joint bidding restrictions. It does not change the current policies on and requirements for bidding systems, joint bidding restrictions, or royalty suspensions for leases issued before December 2000. It does add one minor reporting requirement for all leases issued with royalty suspension and specifies the allocation of royalty relief on a field having leases issued before and after 2000. It also clarifies and rewrites in plain-language the current rental regulations at 30 CFR 218.151 to provide for lessees to pay rental fees during the period of royalty suspension.

DATES: This final rule is effective March 26, 2001.

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

SUPPLEMENTARY INFORMATION: On September 14, 2000, we published a proposed rule in the **Federal Register** (65 FR 55476) stating that we intend to continue OCS leasing incentives in the deep water Gulf of Mexico (GOM) but will implement incentive provisions differently from previous lease sales. Also, we used this occasion to restate in a plain-language format the existing bidding system rules without altering their meaning. This final rule now modifies some provisions in the September 14, 2000, proposed rule.

We proposed four primary changes to the way we have been implementing leasing incentives. In the future, we will establish in the notice of sale, instead of in regulation, the size and form of royalty relief and associated parameters, such as the water depth demarcations where royalty suspension (RS) volumes apply and the price thresholds above which we interrupt RS. Unlike eligible leases issued from 1996 through 2000, future deep water leases, even those issued with RS volumes, may apply for supplemental royalty relief under our discretionary authority in 30 CFR 203. We will assign RS volumes to individual leases rather than, as previously, to fields. Finally, lessees will owe rental but no minimum royalties in any full year in which they pay no royalties on production. Currently, lessees owe rentals until discovery and then minimum royalties until production under royalty suspension begins. The intent to change the current rule and provide for rentals during royalty suspension periods was not perfectly captured in the proposed regulation, but was included in the preamble to the proposed rule. The preamble explained that rentals during royalty suspension periods are analogous to a holding fee collected during capital recovery periods when net profit share leases pay rental but no royalty. In the proposed rule we asked for comments on these leasing incentive adjustments.

In conjunction with this rulemaking, on November 16, 2000, we published another proposed rule in the **Federal Register** (65 FR 58258) describing adjustments to our discretionary relief process. Among other things, this discretionary proposed rule makes leases issued after November 2000 in water 200 meters or deeper in the GOM wholly west of 87 degrees, 30 minutes West longitude eligible to apply for supplemental royalty relief. Also, it proposed to modify the relief qualification process in ways that should allow more applicants on pre-Act leases to qualify for relief and more flexibility for companies on both pre-Act and all new deep water leases to adjust development plans without sacrificing the chance for relief. We also sought and will consider comments we receive on that rule.

Response to Comments

Thirteen respondents—a joint one from 6 oil and gas industry associations, a separate one from one of those associations, 10 oil and gas companies and the Department of Energy—submitted comments on the leasing incentive and bidding rule. Copies of all the comments we received are available on our website at *http://www.mms.gov/federalregister/PublicComments/rulecomm.htm.*

Several comments took issue with some of our bidding system rules. As we are not proposing to change the substance of the existing rules, we take those comments as indicative of confusion created by our plain-language rewrite. We clarify in this final rule those confusing portions of the proposed rewrite.

The requirement to notify us when royalty-free production begins is the only change from the current regulation that we proposed to the way royalty suspensions apply to eligible leases issued from 1996 through 2000. No respondents objected to this notification requirement and we finalized that provision without modification. The only other new element that affects existing eligible leases is that a future RS lease may be on the same field. The new regulations in § 260.124 govern royalty suspension in this situation.

Most comments addressed specific questions raised in the introduction to the proposed rule. The following summarizes those comments and our responses in four sections—design of future royalty suspensions, adjustable lease-based royalty suspension, rental payments and relief suspension during high prices, and bidding issues.

Design Issues

Four questions sought guidance on design issues for future lease sales. Responses to the question on what factors we should consider, and how we should consider them, when choosing water depths at which to offer royalty relief focused on four items:

- Shortage of rigs capable of drilling in water depths greater than 1600 meters;
- Lack of infrastructure in water depths greater than 1600 meters;
- The multitude of challenges (reservoir connectivity, reservoir performance, rig price fluctuations, limited production experience, undeveloped and relatively untested technology, distance from support infrastructure, higher development costs, and shallow water flow) to operations in water depths greater than 1500 meters; and
- The relatively lower quality of remaining prospects in the 200 to 1600 meter water depth area.

No one suggested ways to rank or measure the relative significance of these factors or how to relate them to the issue of whether we should provide any RS volumes. Also, the comments seem to argue that a rationale can be made for royalty relief in all deep water.

Responses to the question on what elements other than water depth to consider, and how we should consider them, in deciding on the size of RS volumes also can be categorized into four groups:

- Unusual drilling challenges such as subsalt targets, extreme well depths, and drilling encountering high pressure/high temperature zones;
- Unusual production challenges such as distance to available

infrastructure, high sulphur and low API gravity crude oils, and areas with a history of poor reservoir performance;

• The value of increased competition from greater bidding interest sparked by royalty relief; and

• Shortage of domestic investment alternatives for the offshore oil and gas industry due to the absence of OCS lands available for leasing outside the GOM.

Again, beyond identification of these elements, the comments offered little in the way of guidance on how to evaluate these considerations relative to others such as the need to obtain fair market value for public resources and the desire to use the incentive efficiently. Nonetheless, like those to the previous question, these comments identify elements we will consider in choosing RS parameters. This rule does not establish those parameters, so those comments will be considered more fully as part of future notice of sale processes that will establish these parameters.

The question on the choice between low RS volumes followed by normal royalty rates or high RS volumes followed by above normal royalty rates found a large preference for the former. The principal reasons given included aversion to variable royalty rates, a wish not to confound the bidding and exploration incentive offered by RS volumes with disincentive changes in other lease terms, and a recognition that supplemental relief can reinforce modest RS volumes where truly needed. One comment did note that smaller, riskier prospects may benefit more from the larger RS volumes than a lower eventual royalty rate.

The final design question about the shift in risk associated with RS volumes elicited no responses that smaller companies feel disadvantaged either in bidding or development relative to larger companies.

One comment suggested that we are defining too narrowly this framework for royalty relief by mentioning only suspension of royalty for a volume of production. The Deep Water Royalty Relief Act (the Act) also authorized suspensions for a time or value of production. To keep open that possibility, we refer to a more general royalty suspension rather than a royalty suspension volume in §§ 260.120, 260.121 and 260.124.

Adjustable Leased-based Royalty Suspension

Responses generally agreed with our observation that lease-based royalty suspension is preferable to field-based royalty suspension. Many comments voiced the need for certainty and stability in lease sale terms and asserted that field-based RS volumes introduce uncertainties into planning that diminish some of the positive impact of royalty relief on prospect economics. Several comments tentatively supported lease-based relief, but worried that intermixing the lease-based program with the field-based program may create uncertainty. We disagree because the proposed provisions confine uncertainty about realization of RS volumes to eligible leases; i.e., those issued under the field-based system. The current regulation makes it clear that a field's RS volume is to be shared by all the leases in a field entitled to share the royalty suspension volume. The new RS leases are simply a new kind of lease entitled to share this volume. The new element is that, unlike with eligible leases or pre-Act leases that qualify for an RS volume, the field's production timing and magnitude do not affect the royalty relief available to the new RS leases. Also, the proposed provisions do not increase the degree of uncertainty faced by eligible or pre-Act leases, had the field-based system continued. New leases issued with lease-based RS volumes share from a volume sufficient to make the field economic, just as would other eligible leases or pre-Act leases that qualify for a royalty suspension.

In the proposed rule, we inadvertently proposed to change the period allowed for a challenge to a field designation from 15 to 30 days in §§ 260.114 and 260.124. We did not mention this as a change in the preamble to the proposed rule because we did not intend to propose this change. No one commented on the change. To avoid the inevitable confusion and administrative problem of different appeal periods for leases issued at different times, we adjust the proposed rule language to retain the 15-day appeal period to all leases.

Additional steps that some respondents requested to reduce the uncertainty for eligible leases are beyond the scope of this rulemaking. The main step identified was designation of which blocks are on which fields before drilling proves the presence of hydrocarbons. Note that we publish the procedure we use to decide on which field a well on a lease lies, so companies can form their own judgment of what we will decide after the well is drilled. It is our position that to do more and actually preview our likely field decision could risk divulging others' proprietary data and possibly misdirect companies if we subsequently acquire new well or other data.

Some responses to our question about basing uniform RS volumes on the needs of a typical tie-back-sized field pointed out that in doing so we should consider additional factors. Those factors include:

• the expectation that the bigger and better situated tie-back fields already have been leased,

• the uncertainty a resource owner faces about access to another's facilities, and

• the chance that user charges will transfer the benefit of the RS from the reserve owner to the facility owner.

Others simply opposed basing RS volumes on tie-backs at all. Those that opposed using tie-backs as a basis argued that many potential tie-back-sized fields may be developed as stand-alones because they have one or more of the following characteristics. The fields:

(1) Consist of multiple reservoirs that require numerous recompletions;

(2) Involve a large numbers of wells because they lack reservoir continuity; or

(3) Depend on the use of secondary recovery techniques (e.g., water injection). Others noted the current absence of infrastructure to host tie-backs in ultra-deep water.

In general, we view situations with these unusual characteristics as exceptions to be handled by the combination of automatic and supplemental relief. An efficient leasing incentive must focus on a standard volume adequate to encourage bidding and exploration on fields not yet leased and the kind of development most likely to occur on those fields. Should experience indicate, we retain the flexibility under this new rule to offer larger RS in the future. In the meantime, offering larger RS volumes based on stand-alone development would grant excessive royalty relief for the way many of the unleased fields are likely to develop.

On the subject of supplemental relief, we received one comment related to the breadth of our royalty relief authority. One respondent noted that the OCS Lands Act gives the Secretary of the Interior discretionary authority to reduce or eliminate royalties on producing or non-producing leases, and that the Act does not specifically prohibit granting discretionary relief outside the GOM west of 87 degrees, 30 minutes West longitude. We disagree because the OCS Lands Act only authorizes royalty relief to increase production, implying that the lease is already on production. Only the Act authorized relief to promote development, implying that a lease has not yet produced, and the Act limits these authorities to the GOM west of 87 degrees, 30 minutes West longitude.

Several responses to our intention to assume two to three leases per field developed as a tie-back argued that we should make no assumption about field size or makeup. Others advocate adjustment in the lease-based relief for fields that prove to underlie fewer leases. Yet many of the same respondents urged certainty and clarity on future royalty relief provisions. Since we typically estimate the economics of unleased and undiscovered resources on a field basis, lease-based relief requires some transformation from field to lease. Our judgment is that we make relief more certain when we estimate a generic field's financial needs and convert this to a lease size before the lease sale. The most logical and administratively simple way to do the conversion is by using typical numbers of leases per field derived from relevant experience. The alternative of waiting to set the RS volume until a field is discovered and its boundaries determined does not eliminate the uncertainty about the RS volume that a lease ultimately receives. In fact, it would reintroduce some of the uncertainty and contention we currently have with the field as the primary basis of royalty relief.

Two features are likely to help correct any errors in an assumption about the specific number of leases per field. First, the assumption of two to three leases per field is based on our experience to date with fields, most of which we recognize are in shallow water and involve a smaller average field size. Our analysis shows that the deep water fields likely to be leased and discovered over the next few years will tend to cover more leases. In that circumstance, lease specific relief set at ½ to ⅓ the volume appropriate for a typical field will result in the actual field getting more royalty relief. Second, if experience proves that two to three leases are not representative for deep water fields, we can then adjust RS volumes for new leases offered in subsequent sales.

Respondents generally applauded our intention to wait at least 3 years before modifying the initial RS volumes and the other parameters. Benefits cited included easier planning and better decisions because a 3-year commitment allows time for seismic acquisition and interpretation. This time period also affords MMS the opportunity to examine how well the program is working over several lease sales. One comment recommended a 5-year commitment coinciding with our 5-year OCS leasing program. While we recognize the value of a multiyear commitment on lease terms, we do not believe it prudent to include it in a regulation. Rapid changes either in the GOM or in the larger oil and gas market may indicate a change in lease terms that can be accomplished more expeditiously in the sale notice.

Rental Policy Change and Relief Suspension During High Prices

Respondents identified three kinds of effects—conflicting message, minimal, and confusion—from our proposal to extend the rental obligation until royalty payments begin. The conflicting message is that rental payments detract from the RS incentive by imposing a payment during the period when we suspend royalties. Others admitted this payment is minimal given the many millions it takes to develop successfully deep water prospects and the value of the royalties saved due to the RS and is consistent with a long tradition of an annual maintenance fee on OCS leases. Confusion could arise because existing lease forms have first a rental then a minimum royalty equivalent to the rental, even before production begins. Future lease forms will impose only a rental during periods when no royalty payments are due and then impose minimum royalties only as a floor for those royalty payments. We do clarify in 30 CFR 218.151 that the due date for rental after a discovery shifts to the end of the lease year.

One comment recommended simply extending minimum royalties to the RS periods, rather than subjecting all future leases to rentals for an extended period. The proposed treatment has a similar effect on future leases sold without an RS, as they would pay no more in fees than they would under the previous rules. While there could be some difference for leases sold with RS, we deem it inadvisable to introduce the administrative burden of making a hypothetical royalty calculation when no royalty is really due. Clarifying the designation of this single holding fee as a rental payment when no royalty is due should help avoid future confusion.

On another rental issue, some respondents expressed concern that we are changing the requirements about collecting rentals from a non-producing part of a partitioned lease. Our requirements on this issue have not changed from what they were before this plain-language rewrite. We do not collect rentals from the non-producing part of a lease. However, when a newly formed lease occurs as a result of segregation, we do collect rental from a non-producing part of a block.

Some respondents opposed having price thresholds set in sale notices and perhaps periodically adjusted, even though any adjustments would apply only to newly issued leases, not those already issued. Price thresholds are oil and gas prices above which lessees owe royalties despite RS. Most comments objected to the reduced predictability amidst all the other uncertainty in deep water development. It is important to reiterate that once set for a given lease, the price threshold will not change. Only future leases would be subject to any new price threshold. One comment opposed adjusting price thresholds in general since oil and gas price increases drive up costs due to increased utilization of rigs, labor, and equipment. We continue to believe it is better to be able to adjust thresholds if necessary for newly issued leases. Otherwise, we could be locked into an inappropriate price threshold. Perceptions about future prices both drive investment decisions and evolve over time, so the option to change price thresholds for new leases benefits the initial threshold choice because it allows for future adjustments.

A related issue drew either no comments or expressions of confusion. Current policy, following the language of the Act, makes royalties due from the whole previous year if that year's average price exceeds the threshold. That fact cannot be known for certain until several months after the end of a year, so lessees could end up at that time owing back royalties for the past year. One alternative is to apply the thresholds on a real time, rather than retrospective basis. The absence of comments on this issue may simply reflect an acceptance of the existing administrative procedures stated in the Act.

Responses to our question about the appropriate magnitude of price thresholds raised a variety of issues. Some wanted no price thresholds, since those willing to take the risks of deep water exploration and production should not be additionally burdened with the risk of losing the RS incentive. Others essentially took the same position by stating that any price thresholds should be so high that they are not breached by historic price fluctuations, since industry bears the brunt of price cycles. We disagree with this position because we design RS terms assuming some price expectations by the lessee, and those terms lose legitimacy when prices diverge too much from those expectations.

Several respondents agreed that the price thresholds with annual inflation adjustments are reasonable but see no reason to change from the levels set in the Act. Absent compelling analysis supporting the Act's choice of price thresholds, we estimated appropriate ones, given today's economic conditions. Briefly, that estimate involved collecting the price expectations that presumably drive current investment decisions, some based on little or no royalty obligations, and then finding the increases from those prices that match the economic effect of forgiving royalties with reference to the minimum economic field size. Price thresholds of about 10 percent below the ones set in the Act result from this exercise.

Several respondents also commented that regardless of the size of the price thresholds, our policy should be that production does not count against any remaining RS volume when it occurs during a period when prices exceed the threshold. But, this is contrary to the reason for having the thresholds in the first place. That is, at sufficiently high prices, the benefits on revenue preclude the need for relief on this production. If this production does not count against the RS volume, the production at high prices and profits that fully replace the royalty relief gets, in effect, a double incentive.

We have clarified the price threshold language to make it more consistent with the application of the price threshold trigger and collection logistics mandated previously by Congress in the Act. The proposed rule intended maximum flexibility in the timing of the threshold and the collection of royalty by leaving the details for inclusion in future notices of sale. The final rule mimics the previous threshold rule except it does not adopt the calendar year as the time period for always calculating the price threshold. Rather, it allows some flexibility for a different time period. We retain the NYMEX as the pricing benchmark and the royalty collection process after the fixed price threshold time period.

Bidding Rules

We did not ask for comments on our bidding policy rules because we are not proposing to change them. Nevertheless, we received comments on 2 issues—prohibition of agreements after a lease sale and use of multiple bidding systems and variables—that deserve response.

The intent of § 260.303(d) is not to prevent restricted bidders from entering into agreements after we award a lease. Rather, subsection (d) prohibits pre-sale agreements between restricted bidders whereby one restricted bidder would commit to assigning part of a lease to another restricted bidder after the sale is completed. Specifically, subsection (d) prohibits restricted bidders A and B from entering into an agreement *prior* to a lease sale. The reason for this prohibition is to eliminate pre-sale agreements that might cause A to bid on a tract, and implicitly keep B from bidding, or cause B to submit a low bid because, if successful, A may assign a part of the lease to B. The current regulations at § 260.303(c) already prohibit pre-bid agreements between restricted joint bidders. However, to clarify the intent of the new subsection (d), the phrase ''prior to a lease sale'' is inserted after the word ''agreement.''

The first sentence in § 260.110 makes it clear that we will apply a single bidding system and variable to each tract in a lease sale. However, we do intend to use multiple systems in a single sale, for instance offering some tracts with a royalty suspension and others with no royalty suspension, as we have for the last 5 years.

Procedural Matters

Regulatory Planning and Review (Executive Order 12866)

According to the criteria in Executive Order 12866, this rule is a significant regulatory action. The Office of Management and Budget (OMB) makes the final determination under Executive Order 12866.

a. This rule will not have an annual economic effect of $100 million or adversely affect an economic sector, jobs, the environment, or other units of government. This action is a plain-language rewrite of current rules and clarification of policies that may be employed for issuing leases with royalty suspensions in lease sales held after November 2000. There is no assurance that the leasing system option provided in this rule will be used in all future offshore sales. For instance, sustained high prices or a shortage of unleased tracts may cause us to discontinue leasing incentives. Even when used, the leasing system option in this rule will not change substantially the net economic value of production from leases eligible for royalty suspension volumes. Royalty suspension should lead to higher bonuses because future production will be more profitable. Also, more tracts should receive bids because royalty relief makes smaller, more remote fields potentially profitable. But, because the government collects the fair market value of a tract in the up-front bid, the risk that the tract will not prove productive is shifted entirely to the bidder. We do not expect bonus bids to offset fully the anticipated royalty savings on a specific tract. Since these offsetting effects on revenue will play out over an extended period and involve uncertainties that will be assessed differently by the different bidders, we cannot predict the ultimate effect on government receipts. Most of the more prospective tracts have been leased already and the incentives we envision for the next several years are smaller than those mandated by the Act. Thus, we don't expect to see the level of bidding activity experienced in the last 5 years, nor the same level of future royalty reduction. At this point we can say that deep water royalty relief will serve primarily to accelerate the timing of production and redistribute realization of fair market value from royalty to bonus collection. As royalty suspension volumes are an incentive to production, they likely encourage timely exploration in hope of finding reserves, since royalty relief has no value unless and until production occurs. This acceleration will have a beneficial effect on offshore oil industry production and jobs in the near term.

b. This rule will not create inconsistencies with other agencies' actions because there are no changes in requirements from the existing rule.

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

d. This rule will raise novel legal or policy issues. Although this action is basically the rewrite of an existing rule in plain language and sets up a more flexible framework to continue current royalty suspension policies for future sales, it comes at a time when oil and gas prices are unusually high. Some may question the need to continue leasing incentives. We believe royalty suspension remains necessary in a scaled-down and more flexible format because prices can fall as well as rise. Also, a continued program reduces disruptions associated with an abrupt termination of incentives and resultant pressure to continue the rigid, outdated, and expiring terms of the Act.

Regulatory Flexibility (RF) Act

The Department certifies that this rule would not have a significant economic effect on a substantial number of small entities under the RF Act (5 U.S.C. 601 *et seq.*). The provisions of this rule will not have a significant economic effect on offshore lessees and operators, including those that are classified as small businesses. The rule will authorize royalty relief to certain OCS leases awarded in sales held after November 2000. New regulatory provisions will offer firms, large and small, economic incentives to acquire and develop deep water leases in the GOM.

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

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

Under the North American Industry Classification System Code, 211111, Crude Petroleum and Natural Gas Extraction, MMS estimates that a total of 1,380 firms drill oil and gas wells onshore and offshore. The group most affected by this rule is the approximately 130 companies that are offshore lessees/operators. According to SBA criteria, 39 companies qualify as large firms, leaving up to 91 companies that may qualify as small firms with fewer than 500 employees. However, because of the extremely high cost and technical complexity involved in exploration and development in deep water, the vast majority of lessees/operators that will be affected by this rule will be large companies. Nineteen of the 26 lessee/operators that have registered a total of 211 discoveries by mid-year 2000 in deep water (200 meters and greater) are not small and these 19 large firms account for over 91 percent of the total discoveries. The rule envisions limiting incentives to deep water where the presence of large firms is even more prevalent. Virtually all of the prospective tracts in the part of deep water where small firms traditionally operate are already under lease.

This rule would add costs in two areas where there are no costs under the existing rules and the deep water royalty relief terms associated with eligible leases. First, lease terms for eligible leases suspended all payments, including rents and minimum royalties, after start of production on the lease and until the mandated royalty suspension volumes were fully produced. This rule would require that lessees of leases issued in sales after the effective date of this rule must continue to make annual rental payments after a discovery. Rental payments will be due during any year after discovery when no royalty payments are due. Rentals would replace minimum royalties between discovery and start of production for those leases. Experience to date (mid-2000) shows that only four leases are actually producing under the royalty suspension terms set by the Act. Both of the two operators involved happen to be small businesses. If that experience continues for leases issued after this rule, we might expect that perhaps one such lease may produce by 2004, and two more might produce by 2005. Thus, these new leases, irrespective of the size of the lessee, may pay extra rentals ($43,200/lease/year) of $172,800, or an average over the next 5 years of just below $35,000/year. This estimate presumes that these leases will pay rentals instead of ‘‘minimum royalties’’ between discovery and start of production.

Second, the rule would add the requirement that owners of eligible leases notify MMS prior to initiating production on the leases. We estimate it will take an operator one-half hour to draft, finalize, and send such a notification letter. We envision that this letter will be very brief and give only pertinent data such as lease number, area/block, date production is scheduled to commence, and language requesting confirmation of the amount of royalty relief applicable. We currently have six eligible leases with approved Development Operations Coordination Documents (DOCD) and 264 eligible leases with approved Plans of Exploration (POE). For this analysis, we assume that:

(1) All six leases with approved DOCDs will commence production within the first 5 years;

(2) Thirty percent (79) of the 264 leases with approved POEs will drill a discovery well; and

(3) Twenty-five percent (20) of those leases with a discovery well will obtain a DOCD and commence production.

Based on these assumptions, we estimate that a total of 26 eligible leases will commence production within the next 5 years.

At an estimated paperwork cost of $50 per hour or $25 per notification, the total estimated cost of the notification requirement for the first 5 years in which the rule is in effect is $650 or $130 per year.

Thus, total estimated incremental costs associated with this rule are slightly below $35,000 per year on average through 2005. The annual cost will be spread among lessees whose eligible leases commence production and eventually among leases issued after this rule becomes effective and that produce with a royalty suspension. Based on the ratios found above, small business may incur one-tenth to one-third of this incremental cost. The annual cost for a small business with a lease producing under royalty suspension but paying rental would be approximately $44,000 per year. Even if a small business has several eligible leases commencing production, it is clear that the magnitude of the costs do not impose a significant economic effect on a substantial number of small business entities engaged in multi-million dollar drilling and development activities.

Further, any costs associated with the rule must be viewed in light of the substantial economic benefits to be gained from the suspension of royalty payments on the established volume of production. While estimated averaged annual costs are just under $35,000 per year through 2005, lessees that produce stand to gain tens of millions of dollars in royalty relief from the rule. For example, the standard royalty portion (1/8) of a 9 MMBOE royalty suspension volume is worth $25 to $30 million at current oil and gas prices. Again, small business may claim one-tenth to one-third of this benefit. The potential benefit of royalty relief to a small business can be as high as $10 million/year, several orders of magnitude above the extra cost/year under this rule for a small business operating in deep water.

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

Small Business Regulatory Enforcement Fairness Act (SBREFA)

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

a. Does not have an annual effect on the economy of $100 million or more. This rule rewrites the existing rule and clarifies royalty suspension policies for future sales. This rule does not specify exact royalty suspension parameters, but describes the structure that we will follow in applying sale-specific royalty suspensions to future leases. While royalty suspension volumes for future lease sales are not likely to be as high as the current levels specified in the Act, they will still provide meaningful benefits to large and small business lessees.

In general, royalty suspension redistributes revenues—royalty payments decline during the royalty suspension period, while bonus payments before exploration and tax payments due on extra income to the lessee during the royalty suspension period increase. To benefit from the royalty suspension, the lease must produce. Because only a fraction of tracts leased ultimately produce oil and gas, a relatively small number of tracts actually receive a royalty suspension. To determine the annual effect of the royalty relief system on the economy, both the effects on bonus bids and future royalties need to be considered. Experience from sales (during the 1983 to 1988 period) where leases have had time to run the course of the original lease term show that, on average, only about 15 percent of leases issued go into production. Also, estimates for sales between 1996 and 2000 suggest that bidders bid about a $500,000 premium per royalty suspension lease. Using a ratio of seven leases issued for every one (15 percent) that produces, the Government can expect to collect perhaps $3.5 million in extra bonus revenues for each lease that uses a royalty suspension. That extra bonus will be offset by collection of about $22.5 million less in royalties (e.g., $\frac{1}{8}$ of 9 MMBOE times $20/BOE over the production period (e.g., 2010 to 2020). If extra taxes reclaim about $\frac{1}{3}$ of the royalty cost savings, those are comparable sums on a present value basis (e.g., $7 \times \$0.5$ approximately = $20 ($1\frac{1}{3} \times 0.26$ where 0.26 is a discount factor for payments received 10 to 20 years in the future). Thus, even when scaled up to cover sales of hundreds of leases in any one year, this rule will not have an annual effect on the economy of $100 million or more.

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

c. Does not have significant adverse effects on competition, employment, investment, innovation, or the ability of United States-based enterprises to compete with foreign-based enterprises. Leasing on the United States OCS is limited to entities as specified in 30 CFR 256.35. This rule does not change that requirement, so it does not change the ability of United States firms to compete in any way.

Unfunded Mandates Reform Act (UMRA)

This rule does not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than $100 million per year. The rule does not have a significant or unique effect on State, local, or tribal governments. The rule describes the existing regulation in plain language and clarifies royalty suspension policies for OCS lease sales held after November 2000. A statement containing additional UMRA (2 U.S.C. 1531 *et seq.*) information is not required.

Takings Implications Assessment (Executive Order 12630)

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

Federalism (Executive Order 13132)

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

Civil Justice Reform (Executive Order 12988)

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

Paperwork Reduction Act (PRA) of 1995

According to the PRA (44 U.S.C. 3501 *et seq.*), as part of the Notice of Proposed Rulemaking process, OMB approved the collection of information in the proposed regulations and assigned OMB control number 1010–0143. We did not receive any comments opposing the information collection aspects of the proposed rule, and the final rule makes no change in the information collection requirements. The PRA provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

The title of the collection of information for this rule is ''30 CFR Part 260—Outer Continental Shelf Oil and Gas Leasing.'' The requirement to respond is required to obtain or retain a benefit. The information collection requirements and estimated burdens are:

(1) In § 260.114(c), respondents must notify MMS of their intention to begin production, and they must request confirmation of the size of the royalty suspension volume that applies to their eligible lease. We estimate the burden to be one-half hour per notification, and that we would receive five-to-six notices annually.

(2) In §§ 260.114 and 260.124, there is a provision for a lessee or other affected lessees to request reconsideration of MMS's assignment of a lease that has a qualifying well to an existing field or designate a new field. We estimate the burden can range between 80 and 1,000 hours per request for reconsideration. That wide range reflects the fact that fields can underlie from 1 to more than 10 leases, can include from 1 to several dozen reservoirs, or can require simple to complex geological and geophysical interpretations. Because a favorable field assignment can save a lessee tens of millions of dollars in royalties, we may get as many simple as complex appeals. For purposes of estimating burden, we assume that we receive three or four annually, uniformly spread over the simple to complex range with an average burden of 400 hours.

We estimate the total annual reporting ''hour'' burden for the 30 CFR part 260 regulations to be about 1,600 hours. This includes the time for reviewing instructions, searching existing data sources, and gathering the data. There are no recordkeeping requirements.

National Environmental Policy Act (NEPA) of 1969

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

Government-to-Government Relationship with Tribes

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

List of Subjects

30 CFR Part 218

Continental shelf, Methods of payment, Mineral royalties, Public lands—Mineral resources, Royalty payments. Net profit share payment, Rental payments.

30 CFR Part 256

Administrative practice and procedure, Continental shelf, Environmental protection, Government contracts, Mineral royalties, Oil and gas exploration, Pipelines, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements, Surety bonds.

30 CFR Part 260

Bidding system, Continental shelf, mineral royalties, Oil and gas leasing, Reporting requirements, Restricted joint bidder, Royalty suspension.

Dated: February 16, 2001.

Piet deWitt,

Assistant Secretary, Land and Minerals Management.

For the reasons stated in the preamble, the Minerals Management Service (MMS) amends 30 CFR parts 218, 256, and 260 as follows:

PART 218—COLLECTION OF ROYALTIES, RENTALS, BONUSES AND OTHER MONIES DUE THE FEDERAL GOVERNMENT

1. The authority citation for part 218 continues to read as follows:

Authority: 25 U.S.C. 396 *et seq.*, 396a *et seq.*, 2101 *et seq.*; 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*; 31 U.S.C.A. 3335; 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, 1801 *et seq.*

2. In § 218.151, the section heading is revised, an introductory paragraph is added, paragraphs (a) and (b) are revised; paragraphs (c) and (d) are removed; and paragraph (e) is redesignated as paragraph (c) to read as follows:

§ 218.151 Rental Fees.

The annual rental paid in any year is in addition to, and is not credited against, any royalties due from production. The lessee must pay an annual rental as shown in paragraphs (a), (b), and (c) of this section. Discovery means one or more wells on the lease that meet the requirements in 250, subpart A of this title.

(a) This paragraph applies to any lease not covered by paragraph (b) or paragraph (c) of this section.

For—	Issued as a result of a sale held—	The lessee must pay rental—
(1) An oil and gas lease	Before March 26, 2001	On or before the first day of each lease year before the discovery of oil or gas on the lease.
(2) An oil and gas lease	After March 26, 2001	On or before the first day of each lease year before the discovery of oil or gas on the lease, then on or before the last day of each lease year in any full year in which royalties on production are not due.
(3) A mineral lease for other than oil or gas.	Before March 26, 2001	On or before the first day of each lease year before the discovery of paying quantities.
(4) A mineral lease for other than oil or gas.	After March 26, 2001	On or before the first day of each lease year before the date the first royalty payment is due on the lease, then on or before the last day of each lease year in any full year in which royalties on production are not due.

(b) This paragraph applies to any lease created by segregating a portion of a producing lease when there is no actual or allocated production on the segregated portion. The lessee must pay an annual rental for the segregated portion at the rate specified in the lease. The lessee must pay the rental as shown in the following table.

If the lease results from a segregation—	The lessee must pay rental—
(1) Before March 26, 2001	On or before the first day of each lease year before the discovery of oil or gas on the segregated portion.
(2) After March 26, 2001	On or before the first day of each lease year before the discovery of oil or gas on the lease, then on or before the last day of each lease year in any full year in which royalties on production are not due.

(c) * * *

PART 256—LEASING OF SULPHUR OR OIL AND GAS IN THE OUTER CONTINENTAL SHELF

3. The authority citation for part 256 continues to read as follows:

Authority: 42 U.S.C. 6213 and 43 U.S.C. 1331, *et seq.*

4. In § 256.40, the introductory paragraph is revised to read as follows:

§ 256.40 Definitions

The following definitions apply to §§ 256.38 through 256.44 of this part.

* * * * *

5. Part 260 is revised to read as follows:

PART 260—OUTER CONTINENTAL SHELF OIL AND GAS LEASING

Subpart A—General Provisions

Sec.

Subpart B—Bidding Systems

Eligible Leases

Royalty Suspension (RS) Leases

Authority: 43 U.S.C. 1331 *et seq.*

Subpart A—General Provisions

§ 260.1 What is the purpose of this part?

Part 260 implements the Outer Continental Shelf Lands Act (OCSLA), 43 U.S.C. 1331 *et seq.*, as amended, by providing regulations to foster competition including, but not limited to:

(a) Implementing alternative bidding systems;

(b) Prohibiting joint bidding for development rights by certain types of joint ventures; and

(c) Establishing diligence requirements for Federal OCS leases.

§ 260.2 What definitions apply to this part?

OCS lease means a Federal lease for oil and gas issued under the OCSLA.

OCSLA means the Outer Continental Shelf Lands Act, (43 U.S.C. 1331 *et seq.*), as amended.

Person includes, in addition to a natural person, an association, a State, or a private, public, or municipal corporation.

We means the Minerals Management Service (MMS).

You means the lessee or operating rights holder.

§ 260.3 What is MMS's authority to collect information?

The Paperwork Reduction Act of 1995 (PRA) requires us to inform you that we may not conduct or sponsor and you are not required to respond to a collection of information unless it displays a currently valid OMB control number. OMB approved the information collection requirements in part 260 under 44 U.S.C. 3501 *et seq.* and assigned OMB control number 1010–0143. The PRA also requires us to inform you of the following:

(a) We use the information collected under §§ 260.114(a)(2), (c)(1) and 260.124 (a)(2):

(1) To make decisions on requests for reconsideration of our assignment of a lease that has a qualifying well to an existing field or designate a new field under §§ 260.114(a) and 260.124(a), and

(2) To ensure that the royalty suspension volume is properly allocated among constituent leases in a field under § 260.117.

(b) Respondents are Federal OCS oil and gas lessees and operating rights holders. Responses are required to obtain or retain a benefit. We will protect proprietary information under applicable law and part 250 of this chapter.

(c) You may send comments regarding any aspect of the collection of information under this part, including suggestions for reducing the burden, to the Information Collection Clearance Officer, Minerals Management Service, Mail Stop 4230, 1849 C Street, NW., Washington, DC 20240.

Subpart B—Bidding Systems

General Provisions

§ 260.101 What is the purpose of this subpart?

This subpart establishes the bidding systems that we may use to offer and sell Federal leases for the exploration, development, and production of oil and gas resources located on the OCS.

§ 260.102 What definitions apply to this subpart?

Act means the Outer Continental Shelf Deep Water Royalty Relief Act, Pub. L. 104–58, 43 U.S.C. 1337(3).

Eligible lease means a lease that:

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

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

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

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

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

Highest responsible qualified bidder means a person who has met the appropriate requirements of 256, subpart G of this title, and has submitted a bid higher than any other bids by qualified bidders on the same tract.

Highest royalty rate means the highest percent rate payable to the United States, as specified in the lease, in the amount or value of the production saved, removed, or sold.

Lease period means the time from lease issuance until relinquishment, expiration, or termination.

Lowest royalty rate means the lowest percent rate payable to the United States, as specified in the lease, in the amount or value of the production saved, removed, or sold.

OCS lease sale means the Department of the Interior (DOI) proceeding by which leases for certain OCS tracts are offered for sale by competitive bidding and during which bids are received, announced, and recorded.

Pre-Act lease means a lease that:

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

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

(3) Lies wholly west of 87 degrees, 30 minutes West longitude. (See part 203 of this title.)

Production period means the period during which the amount of oil and gas produced from a tract (or, if the tract is unitized, the amount of oil and gas as allocated under a unitization formula) will be measured for purposes of determining the amount of royalty payable to the United States

Qualified bidder means a person who has met the appropriate requirements of § 256, subpart G of this title.

Royalty rate means the percentage of the amount or value of the production saved, removed, or sold that is due and payable to the United States Government.

Royalty suspension (RS) lease means a lease that:

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

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

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

Tract means a designation assigned solely for administrative purposes to a block or combination of blocks that are identified by a leasing map or an official protraction diagram prepared by the DOI.

Value of production means the value of all oil and gas production saved, removed, or sold from a tract (or, if the tract is unitized, the value of all oil and gas production saved, removed, or sold and credited to the tract under a unitization formula) during a period of production. The value of production is determined under part 206 of this title.

§ 260.110 What bidding systems may MMS use?

We will apply a single bidding system selected from those listed in this section to each tract included in an OCS lease sale. The following table lists bidding systems, the bid variables, and characteristics.

For the bidding system—	The bid variable is the—	And the characteristics are—
(a) Cash bonus bid with a fixed royalty rate of not less than 12.5 percent.	Cash bonus	The highest responsible qualified bidder will pay a royalty rate of not less than 12.5 percent at the beginning of the lease period. We will specify the royalty rate for each tract offered in the Notice of OCS Lease Sale published in the **Federal Register**.
(b) Royalty rate bid with fixed cash bonus.	Royalty rate	We will specify the fixed amount of cash bonus the highest responsible qualified bidder must pay in the Notice of OCS Lease Sale published in the **Federal Register**.
(c) Cash bonus bid with a sliding royalty rate of not less than 12.5 percent at the beginning of the lease period.	Cash bonus	(1) We will calculate the royalty rate the highest responsible qualified bidder must pay using either: (i) A sliding-scale formula, which relates the royalty rate to the adjusted value or volume of production, or (ii) A schedule that establishes the royalty rate that we will apply to specified ranges of the adjusted value or volume of production. (2) We will determine the adjusted value of production by applying an inflation factor to the actual value of production. (3) If you are the successful high bidder, your lease will include the sliding-scale formula or schedule and will specify the lowest and highest royalty rates that will apply. (4) You will pay a royalty rate of not less than 12.5 percent at the beginning of the lease period. (5) We will include the sliding-scale royalty formula or schedule, inflation factor and procedures for making the inflation adjustment and determining the value or amount of production in the Notice of OCS Lease Sale published in the **Federal Register**.
(d) Cash bonus bid with fixed share of the net profits of no less than 30 percent.	Cash bonus	(1) If we award you a lease as the highest responsible qualified bidder, you will determine the amount of the net profit share payment to the United States for each month by multiplying the net profit share base times the net profit share rate, according to § 220.022. You will calculate the net profit share base according to § 220.021. (2) You will pay a net profit share of not less than 30 percent. (3) We will specify the capital recovery factor, as described in § 220.020, and the net profit share rate, both of which may vary from tract to tract, in the Notice of OCS Lease Sale published in the **Federal Register**.
(e) Cash bonus with variable royalty rate(s) during one or more periods of production.	Cash bonus	(1) We may suspend or defer royalty for a period, volume, or value of production. Notwithstanding suspensions or deferrals, we may impose a minimum royalty. The suspensions or deferrals may vary based on prices or price changes of oil and/or gas. (2) You may pay a royalty rate less than 12.5 percent on production but not less than zero percent. (3) We will specify the applicable royalty rates(s) and suspension or deferral magnitudes, formulas, or relationships in the Notice of OCS Lease Sale published in the **Federal Register**.
(f) Cash bonus with royalty rate(s) based on formula(s) or schedule(s) during one or more periods of production.	Cash bonus	We will base the royalty rate on formula(s) or schedule(s) specified in the Notice of OCS Lease Sale published in the **Federal Register**.
(g) Cash bonus with a fixed royalty rate of not less than 12.5 percent, at the beginning of the lease period, suspension of royalties for a period, volume, or value of production, or depending upon selected characteristics of extraction, and with suspensions that may vary based on the price of production.	Cash bonus	Except for periods of royalty suspension, you will pay a fixed royalty rate of not less than 12.5 percent. If we award to you a lease under this system, you must calculate the royalty due during the designated period using the rate, formula, or schedule specified in the lease. We will specify the royalty rate, formula, or schedule in the Notice of OCS Lease Sale published in the **Federal Register**.

§ 260.111 What conditions apply to the bidding systems that MMS uses?

(a) For each of the bidding systems in § 260.110, we will include an annual rental fee. Other fees and provisions may apply as well. The Notice of OCS Lease Sale published in the **Federal Register** will specify the annual rental and any other fees the highest responsible qualified bidder must pay and any other provisions.

(b) If we use any deferment or schedule of payments for the cash bonus bid, we will specify and include it in the Notice of OCS Lease Sale published in the **Federal Register**.

(c) For the bidding systems listed in this subpart, if the bid variable is a cash bonus bid, the highest bid by a qualified bidder determines the amount of cash bonus to be paid. We will include the minimum bid level(s) in the Notice of OCS Lease Sale published in the **Federal Register**.

(d) For the bidding systems listed in this subpart, if the bid variable is the royalty rate, the highest bid by a qualified bidder determines the royalty rate to be paid. We will include the minimum royalty rate(s) in the Notice of OCS Lease Sale published in the **Federal Register**.

(e) We may, by rule, add to or modify the bidding systems listed in § 260.110, according to the procedural requirements of the OCSLA, 43 U.S.C. 1331 *et seq.*, as amended by Public Law 95–372, 92 Stat. 629.

Eligible Leases

§ 260.112 How do royalty suspension volumes apply to eligible leases?

Royalty suspension volumes, as specified in section 304 of the Act, apply to eligible leases that meet the criteria in § 260.113. For purposes of this section and §§ 260.113 through 260.117:

(a) Any volumes of production that are not normally royalty-bearing under the lease or the regulations (e.g., fuel gas) do not count against royalty suspension volumes; and

(b) Production includes volumes allocated to a lease under an approved unit agreement.

§ 260.113 When does an eligible lease qualify for a royalty suspension volume?

(a) Your eligible lease may receive a royalty suspension volume only if it is in a field where no current lease produced oil or gas (other than test production) before November 28, 1995. For eligible leases, the bidding system in § 260.110(g) applies only to leases in fields that meet this condition.

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

§ 260.114 How does MMS assign and monitor royalty suspension volumes for eligible leases?

(a) We will assign your lease that has a qualifying well (under part 250, subpart A of this title) to an existing field or designate a new field and will notify you and other affected lessees and operating rights holders in the field of that assignment.

(1) Within 15 days of that notification, you or any of the other affected lessees or operating rights holders may file a written request with the Director of MMS (Director) for reconsideration accompanied by a ''Statement of Reasons.''

(2) The Director will respond in writing either affirming or reversing the assignment decision. The Director's decision is the final action of the Department of the Interior and is not subject to appeal to the Interior Board of Land Appeals under part 290 of this title and 43 CFR part 4.

(b) We have specified the water depth for each eligible lease in the final Notice of OCS Lease Sale. Our determination of water depth for each lease is final once we issue the lease. We have specified in the Notice the royalty suspension volume applicable to each water depth. The minimum royalty suspension volumes for fields in million barrels of oil equivalent (MMBOE) are shown in the following table:

Water depth	Minimum royalty suspension volume
(1) 200 to 400 meters	17.5 MMBOE
(2) 400 to 800 meters	52.5 MMBOE
(3) 800 meters or more	87.5 MMBOE

(c) Before commencing production, you must:

(1) Notify the MMS Regional Supervisor for Production and Development of your intention to start production; and

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

(d) When production (other than test production) first occurs from any of the eligible leases in a field consisting only of eligible leases, we will determine what royalty suspension volume applies to the lease(s) in that field. We base the determination for eligible lease(s) on the royalty suspension volumes specified in paragraph (b) of this section and § 260.117(a).

(e) Your eligible lease may obtain more than one royalty suspension volume. If a new field is discovered on your eligible lease that already benefits from the royalty suspension volume from another field, production from that new field receives a separate royalty suspension.

§ 260.115 How long will a royalty suspension volume for an eligible lease be effective?

A royalty suspension volume for an eligible lease will continue through the end of the month in which cumulative production from the leases in a field entitled to share the royalty suspension volume reaches that volume or the lease period ends.

§ 260.116 How do I measure natural gas production on my eligible lease?

You must measure natural gas production on your eligible lease subject to the royalty suspension volume as follows: 5.62 thousand cubic feet of natural gas, measured according to part 250, subpart L of this title, equals one barrel of oil equivalent.

§ 260.117 What other provisions apply to royalty suspension volumes for eligible leases?

In addition to the provisions in §§ 260.111 through 260.116, the provisions in this section apply to royalty suspension volumes on eligible leases.

(a) If a new field consists of eligible leases in different water-depth categories, the royalty suspension volume associated with the eligible lease in the deepest water applies.

(b) If your eligible lease is the only eligible lease in a field, you do not owe royalty on the production from your lease up to the applicable royalty suspension volume.

(c) If a field consists of more than one eligible lease:

(1) Payment of royalties on the eligible leases' initial production is suspended until cumulative production equals the field's established royalty suspension volume;

(2) Only production from leases entitled to share in the field's royalty suspension volume counts as part of this cumulative production; and

(3) The royalty suspension volume for each eligible lease is equal to each lease's actual production (or production allocated under an approved unit agreement) until the field's royalty suspension volume is reached.

(d) This paragraph applies if we add an eligible lease to a field that has an established royalty suspension volume that we approved under part 203 of this title. This paragraph also applies to a field that has an established royalty suspension volume as a result of production starting from one or more eligible leases in the field. In situations covered by this paragraph:

(1) The field's royalty suspension volume will not change, even if the added lease is in deeper water;

(2) If we granted a royalty suspension volume under part 203 of this title that is larger than the minimum specified for that water depth, the added eligible lease may share in the larger suspension volume;

(3) The eligible lease may receive a royalty suspension volume only to the extent of its production before the cumulative production equals the field's previously established royalty suspension volume; and

(4) Only production from leases entitled to share in the field's previously established royalty suspension volume counts as part of this cumulative production.

(e) A pre-Act lease may receive a royalty suspension volume under part 203 of this title for a field that already has a royalty suspension volume due to eligible leases. If this happens, then:

(1) The eligible and pre-Act leases share a single royalty suspension volume;

(2) The field's royalty suspension volume is the larger of the volume for the eligible leases or the volume MMS grants in response to the pre-Act leases' application; and

(3) The suspension volume for each eligible lease is its actual production from the lease until cumulative production from all leases in the field entitled to share in the field-based suspension volume equals the suspension volume.

(f) If we reassign a well on an eligible lease to another field, the past production from that well:

(1) Will count toward the royalty suspension volume, if any, specified for the field to which it is reassigned; and

(2) Will not count toward the royalty suspension volume, if any, for the field from which it was reassigned.

Royalty Suspension (RS) Leases

§ 260.120 How does royalty suspension apply to leases issued in a sale held after November 2000?

We may issue leases with suspension of royalties for a period, volume or value of production, as authorized in section 303 of the Act. For purposes of this section and §§ 260.121 through 260.124:

(a) Any volumes of production that are not normally royalty-bearing under the lease or the regulations (e.g., fuel gas) do not count against royalty suspension volumes; and

(b) Production includes volumes allocated to a lease under an approved unit agreement.

§ 260.121 When does a lease issued in a sale held after November 2000 get a royalty suspension?

(a) We will specify any royalty suspension for your RS lease in the Notice of OCS Lease Sale published in the **Federal Register** for the sale in which you acquire the RS lease and will repeat it in the lease document. In addition:

(1) Your RS lease may produce royalty-free the royalty suspension we specify for your lease, even if the field to which we assign it is producing.

(2) The royalty suspension we specify in the Notice of OCS Lease Sale for your lease does not apply to any other leases in the field to which we assign your RS lease.

(b) You may apply for a supplemental royalty suspension for a project under part 203 of this title, if your lease lies:

(1) In the Gulf of Mexico,

(2) In water 200 meters or deeper, and

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

(c) Your RS lease retains the royalty suspension with which we issued it even if we deny your application for more relief.

§ 260.122 How long will a royalty suspension volume be effective for a lease issued in a sale held after November 2000?

(a) The royalty suspension volume for your RS lease will continue through the end of the month in which cumulative production from your lease reaches the applicable royalty suspension volume or the lease period ends.

(b)(1) Notwithstanding any royalty suspension under this subpart, you must pay royalty at the lease stipulated rate on:

(i) Any oil produced for any period stipulated in the lease during which the arithmetic average of the daily closing prices on the New York Mercantile Exchange (NYMEX) for light sweet crude oil exceeds a threshold price stipulated in the lease, or

(ii) Any natural gas produced for any period stipulated in the lease during which the arithmetic average of the daily closing prices on the NYMEX for natural gas exceeds a threshold price stipulated in the lease.

(2) You must pay any royalty due under this paragraph, plus late payment interest under § 218.54 of this title, no later than 90 days after the end of the period for which royalty is owed.

(3) Any production on which you must pay royalty under this paragraph will count toward the production volume determined under §§ 260.120 through 260.124.

(c) If you must pay royalty on any product (either oil or natural gas) for any period under paragraph (b), you must continue to pay royalty on that product during the next succeeding period of the same length until the arithmetic average of the daily closing NYMEX prices for that product for that period can be determined. If the arithmetic average of the daily closing prices for that product for that period is less than the threshold price stipulated in the lease, you are entitled to a credit or refund of royalties paid for that period with interest under applicable law.

(d) MMS will adjust the threshold oil and gas prices referred to in paragraph (b) for any period stipulated in the lease by the percentage, if any, by which the implicit price deflator for the gross domestic product changed during the preceding period.

§ 260.123 How do I measure natural gas production for a lease issued in a sale held after November 2000?

You must measure natural gas production subject to the royalty suspension volume for your lease as follows: 5.62 thousand cubic feet of natural gas, measured according to part 250, subpart L of this title, equals one barrel of oil equivalent.

§ 260.124 How will royalty suspension apply if MMS assigns a lease issued in a sale held after November 2000 to a field that has an eligible or pre-Act lease?

(a) We will assign your lease that has a qualifying well (under part 250, subpart A of this title) to an existing field or designate a new field and will notify you and other affected lessees and operating rights holders in the field of that assignment.

(1) Within 15 days of the final notification, you or any of the other affected lessees or operating rights holders may file a written request with the Director for reconsideration, accompanied by a Statement of Reasons.

(2) The Director will respond in writing either affirming or reversing the assignment decision. The Director's decision is the final action of the Department of the Interior and is not subject to appeal to the Interior Board of Land Appeals under part 290 of this title and 43 CFR part 4.

(b) If we establish a royalty suspension volume for a field, either as a result of an approved application for royalty relief submitted for a pre-Act lease under part 203 of this title or as the result of production starting from one or more eligible leases in the field, then:

(1) Royalty-free production from your RS lease shares from and counts as part of any royalty suspension volume remaining for the field to which we assign your lease; and

(2) Your RS lease may continue to produce royalty-free up to the royalty suspension we specified for your lease, even if the field to which we assign your RS lease has produced all of its royalty suspension volume.

(c) Your lease may share in a suspension volume larger than the royalty suspension with which we issued it and to the extent we grant a larger volume in response to an application by a pre-Act lease submitted under part 203 of this title. To share in any larger royalty suspension volume, you must file an application described in §§ 203.71 and 203.83. In no case will royalty-free production for your RS lease be less than the royalty suspension specified for your lease.

Bidding System Selection Criteria

§ 260.130 What criteria does MMS use for selecting bidding systems and bidding system components?

In analyzing the application of one of the bidding systems listed in § 260.110 to tracts selected for any OCS lease sale, we may, at our discretion, consider the following purposes and policies. We recognize that each of the purposes and policies may not be specifically applicable to the selection process for a particular bidding system or tract, or may present a conflict that we will have to resolve in the process of bidding system selection. The order of listing does not denote a ranking.

(a) Providing fair return to the Federal Government;

(b) Increasing competition;

(c) Ensuring competent and safe operations;

(d) Avoiding undue speculation;

(e) Avoiding unnecessary delays in exploration, development, and production;

(f) Discovering and recovering oil and gas;

(g) Developing new oil and gas resources in an efficient and timely manner;

(h) Limiting the administrative burdens on Government and industry; and

(i) Providing an opportunity to experiment with various bidding systems to enable us to identify those most appropriate for the satisfaction of the objectives of the United States in OCS lease sales.

Subpart C [Reserved]

Subpart D—Joint Bidding

§ 260.301 What is the purpose of this subpart?

The purpose of this subpart is to encourage participation in OCS oil and gas lease sales by limiting the requirement for filing ''Statements of Production'' to certain joint bidders.

§ 260.302 What definitions apply to this subpart?

For the purposes of this subpart, all terms used are defined as in § 256.40 of this title.

§ 260.303 What are the joint bidding requirements?

(a) You must file a Statement of Production with the Director, according to the requirements of §§ 256.38 through 256.44 of this title if:

(1) You submit a joint bid for any OCS oil and gas lease during a 6-month bidding period; and

(2) You were chargeable for the prior production period with an average daily production from all sources in excess of 1.6 million barrels of crude oil, natural gas equivalents, and liquefied petroleum products.

(b) The Statement of Production that you file under paragraph (a) of this section must state that you are chargeable for the prior production period with an average daily production in excess of the quantities listed in paragraph (a) of this section.

(c) If your average daily production in the prior production period met or exceeded the quantities specified in paragraph (a) of this section, you may not submit a joint bid for any OCS oil and gas lease during the applicable 6-month bidding period with any other person similarly chargeable. We will disqualify and reject these bids.

(d) If your average daily production in the prior production period met or exceeded the quantities specified in paragraph (a) of this section, you may not enter into an agreement prior to a lease sale that would result in two or more persons, similarly chargeable, acquiring or holding any interest in the tract for which the bid is submitted. We will disqualify and reject these bids.

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