DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Parts 203 and 260

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RIN 1010–AD33

Royalty Relief—Ultra-Deep Gas Wells and Deep Gas Wells on Leases in the Gulf of Mexico; Extension of Royalty Relief Provisions to Leases Offshore of Alaska

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: This final rule amends existing deep gas royalty relief regulations to reflect statutory changes enacted in the Energy Policy Act of 2005. It provides additional royalty relief for certain ultra-deep wells on Outer Continental Shelf leases in shallow water in the Gulf of Mexico. It extends both the existing and the additional deep gas royalty relief to Outer Continental Shelf leases in deeper water than before. Finally, this final rule applies discretionary royalty relief procedures that have been used by deepwater leases in the Gulf of Mexico to leases offshore of Alaska.

EFFECTIVE DATES: This final rule becomes effective December 18, 2008.

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SUPPLEMENTARY INFORMATION:

A. Background

On May 18, 2007, MMS published a proposed rule in the **Federal Register** (72 FR 28396) to implement Sections 344 and 346 of the Energy Policy Act of 2005, Pub. L. No. 109–58, 119 Stat. 594, 702 (codified at 42 U.S.C. 15904). This final rule is substantially the same as the proposed rule except for fixing price thresholds used with application-based royalty relief for leases offshore Alaska and for newer deepwater leases in the Gulf of Mexico (GOM), and the ability of operators to temporarily remove drilling rigs in certain cases without forfeiting the original well status of deep wells. Minor editorial or clarifying language changes were also made. The statutorily-mandated royalty relief provisions in this final rule for deep gas wells in the GOM supplement royalty relief that MMS previously included in 30 CFR 203.40–203.48, hereafter referred to as the existing regulations.

Under the existing regulations, MMS offered a temporary royalty relief incentive for deep gas production from GOM leases in less than 200 meters of water that lie wholly west of 87 degrees, 30 minutes West longitude for wells spudded since March 26, 2003.

The incentive in the existing regulations consists of a royalty suspension volume (RSV) for the first qualifying well on a lease for two basic categories of deep gas production: (1) 15 billion cubic feet (BCF) of RSV for a qualifying well with a perforated interval the top of which is between 15,000 and 18,000 feet true vertical depth subsea (TVD SS); or (2) 25 BCF of RSV for a qualifying well completed at least 18,000 feet TVD SS. The existing regulations provide lesser amounts of royalty relief for a deep sidetrack, for a subsequent deeper well on the lease, and for drilling an unsuccessful deep well. All qualified deep wells on the lease that begin production before May 3, 2009, may use the relief provided in the existing regulations, but only for production that occurs during years when the average price of natural gas on the New York Mercantile Exchange (NYMEX) does not exceed the price threshold of $10.15 per million British thermal units (MMBtu), expressed in 2007 dollars.

The supplemental incentive added by this final rule implementing section 344 of the Energy Policy Act is an RSV of 35 BCF for a third well depth category—an ultra-deep well (defined in section 344(a)(3)(A) as wells with a perforated interval the top of which is at least 20,000 feet TVD SS). The final rule provides that this ultra-deep well incentive has no expiration date, applies only if the lease has no prior deep well production, and is subject to a price threshold of $4.55 per MMBtu, expressed in 2007 dollars.

Also, this final rule provides the same incentive for gas produced from a deep well on leases in waters 200 meters or deeper but less than 400 meters deep as the existing regulation provides on leases in less than 200 meters of water, with 2 exceptions:

1. The incentive in 200 to less than 400 meters of water applies to qualified deep wells spudded on or after May 18, 2007, rather than March 26, 2003, and that begin production before May 3, 2013, rather than before May 3, 2009; and

2. The royalty relief in 200 to 400 meters of water applies to production from qualified wells occurring in years when the average NYMEX natural gas price does not exceed a price threshold of $4.55 per MMBTU, rather than $10.15 per MMBTU, expressed in 2007 dollars.

Finally, to implement section 346 of the Energy Policy Act, this final rule utilizes established royalty relief application and evaluation procedures found under §§ 203.60 through 203.80 for any lease offshore Alaska that seeks royalty relief before production on the lease begins. These case-by-case procedures for seeking royalty relief are the same as can be used by a deepwater lease in the GOM that was issued before the Deep Water Royalty Relief Act of 1995 (DWRRA) or after 2000. Prior to this rulemaking, the pre-production royalty relief procedures in §§ 203.60–203.80 did not apply to leases offshore Alaska. Consistent with section 346 of the Energy Policy Act of 2005, the current rulemaking addresses that omission.

B. Comments Leading to Rule Modifications

Eight respondents submitted comments on the proposed rule. Separate letters from Chevron and from the American Petroleum Institute (API), as well as a joint letter from six oil and gas industry associations (National Ocean Industries Association (NOIA), Independent Petroleum Association of America, U.S. Oil & Gas Association, International Association of Drilling Contractors, American Exploration and Production Council, and Natural Gas Supply Association) expressed concerns mostly about various restrictions in the proposed deep and ultra-deep well provisions. A joint letter from five environmental organizations (Northern Alaska Environmental Center (NAEC), Alaska Wilderness League, Natural Resources Defense Council, Pacific Environment, and Resisting Environmental Destruction on Indigenous Lands) and a separate letter from a representative of another environmental organization (Defenders of Wildlife (DoW)) raised a variety of concerns about royalty relief mostly for leases offshore Alaska. A letter from a private citizen (T. Tupper) critiqued some processes and assumptions included in the proposed rule. Finally, a letter from an energy consuming industry organization (Industrial Energy Consumers of America) expressed general support for the added domestic production incentive, while a letter from another private citizen (K. Sellers) voiced general opposition to royalty relief. Copies of all the comments we received are available on our Web site at: *http://www.mms.gov/federalregister/PublicComments/AD33.htm.*

In response to these comments, the final rule substantively changes one provision of the proposed rule. Also, we have clarified some text in the regulations in response to about one-third of the items on a detailed list in the API comments. Further, we have reorganized parts of the rule by moving provisions from some sections to other sections where they are more appropriately located. These moves do not alter the meaning of the provisions. Finally, we have updated the various base price threshold values from 2006 dollars to 2007 dollars.

The proposed rule explained how the applicable base price thresholds would be determined in the case of a lease offshore Alaska that applies and qualifies for pre-production royalty relief. For a lease issued with royalty relief and price thresholds, those same price thresholds would apply to any additional discretionary relief awarded on a case-by-case basis through the provisions of the proposed rule. For a lease issued without royalty relief and price thresholds, the base price threshold terms in the DWRRA would apply to all royalty relief awarded.

Given the comments received on the proposed rule and further review of our process for evaluating pre-production royalty relief applications, we add flexibility to the price thresholds prescribed in the regulation for leases both offshore Alaska and those in deep water in the GOM issued after 2000. We do this by providing the authority to grant an exception to the price thresholds fixed in § 203.78 in cases where we find a project would not be economic without royalty relief subject to price thresholds above those fixed in the rule. Our process for determining whether development (pre-production) projects or expansion projects need relief requires use of future oil and gas price paths that we specify so as to insure that current oil and gas price expectations are impartially reflected in the evaluation. Should an applicant demonstrate that even at this price path, royalty relief is necessary to transform development of a discovery from an uneconomic to an economic proposition, we may decide that production of the resource with a higher royalty relief price threshold is preferable to stranding the resource.

This exception recognizes that, in many cases, generic price thresholds established in lease terms or for a general category of leases (e.g., all those leases eligible for deep gas or deepwater royalty relief) may be set conservatively to avoid providing excessive relief, since the relief to which the thresholds apply inevitably turns out to be unnecessary for many of those that use it. In those cases, a more parsimonious price threshold properly limits the size of the forgone royalty from those leases that would have been explored and developed without royalty relief. However, it may not be the proper price threshold in specific cases where the individual applicant can demonstrate convincingly that royalty relief is the difference between a prospective profit and loss situation, and thus this relief would directly affect the lessee's decision between development and abandonment of a discovery. In such cases, there is less concern about forgone royalties because it would be presumed that no royalties would be collected without the production that results from providing some initial royalty relief.

We intend to select the price threshold in the case of an exception using the same criteria we do for determining the size of the RSV. That is, we set or raise the oil and gas price thresholds, like we set or raise the RSV, only enough to make development economic on the lease, unit or project that has applied and qualified for royalty relief.

This change responds to comments from both NOIA, *et al.*, and NAEC, *et al.* The concern expressed by NOIA, *et al.*, was that the proposed implementation of section 346 ''stopped in its tracks'' an initial positive reaction to that incentive. While the comment went on to request a step not authorized by the statute, that ultra-deep gas relief be applied to Alaska, it did cause us to look at other ramifications of the provisions applied to Alaska. The proposed base price threshold for certain older leases in Alaska has a greater chance of being exceeded than is the case for the actual price threshold included in newer leases offshore Alaska. These older leases have no royalty relief in their lease terms and so would have been subject, under the proposed rule, to the DWRRA threshold for any newly approved royalty relief. The intent of the proposed rule's provision to implement section 346 was to provide added flexibility to consider, on a case-by-case basis, additional royalty relief for projects that may otherwise prove uneconomic to develop. However, strictly applying the base price threshold to any such relief granted under this provision could have the unintended effect of negating that relief if the project would remain uneconomic at prices above the threshold. The flexibility added by the final rule provision allows for the possibility to apply a different price threshold to relief granted on a case-by-case basis, consistent with the specific circumstances of the project being granted relief.

Further, we observed only a small response to the original deep gas relief in the GOM, which justifies a lower, more restrictive price threshold there to avoid providing excessive royalty relief on production that would occur without that relief. In contrast, the meager Outer Continental Shelf (OCS) production history in Alaska does not provide the same justification for a lower, more restrictive price threshold.

As part of this reconsideration of the Alaska price threshold, we discovered a modification we needed but neglected to propose in § 203.80. That modification authorizes case-by-case applications before production starts for royalty relief in special cases that fall outside our established categorical or formal application-based royalty relief programs from leases offshore Alaska, as well as from leases located wholly west of 87 degrees 30 minutes West longitude in the GOM. This special case royalty relief is available to all leases on the OCS after production begins. Section 346 of the Energy Policy Act of 2005 added leases offshore Alaska to the subset of OCS leases that may seek royalty relief before production begins. Along with this modification, we clarify that our formal royalty relief programs include both the size of the relief (e.g., RSV) we may grant and the conditions (e.g., price threshold) we may impose on use of that relief.

The API provided an extensive list of suggested text clarifications to improve readability and comprehension of the terms under which this royalty relief is available. We have adopted many of those clarifications. Clarifying rule text has been added to: (1) § 203.0 definitions for certified unsuccessful well and ultra-deep short sidetrack; (2) to § 203.2; (3) to section lists at the beginning of the new and revised deep gas and ultra-deep gas sections in subpart B; and (4) to §§ 203.33 and 203.43. Also, we have expanded the explanations in the examples in §§ 203.31, 203.36, 203.41, and 203.43(a) to include not only what the answer is but also why that answer results from the regulation. The API also suggested wording changes in the rule to implement some conceptual changes they favor. Discussion at the end of the next section explains why we did not make these conceptual changes.

During review of the comments on the proposed rule, we discovered a needed technical correction to an existing definition. This technical correction allows temporary removal of a drill rig due to weather (e.g., hurricane) or safety (e.g., unexpected pressure) concerns without sacrificing the well's status as an original well. Provided that drilling resumes within 1 year after drilling was halted due to a weather or safety hazard which we agree justified removing the rig, we will still consider the well an original well for purposes of royalty relief. The sunset dates in the qualified deep and ultra-deep well definition are still applicable in this situation. We do this to avoid creating a moral hazard of encouraging continued operation with a rig that has been or may be damaged by weather or is unsafe to use with newly revealed geologic conditions for the sake of preserving access to royalty relief. When we are encouraging operators with royalty relief to take a chance in untested horizons and areas, we do not want to penalize prudent operation. This flexibility is more important in the case of ultra-deep wells where the change in a well's designation from original well to sidetrack loses all royalty relief.

Finally, we moved provisions appearing in the proposed rule in § 203.31(c) and § 203.41(d) that describe how to apply the RSV to § 203.33(a) and § 203.43(a), respectively, where other provisions concerning the application of an RSV appear. Also, we rearranged the provisions appearing in § 203.35 to match the chronological order in which these administrative actions that secure the RSV should occur, and clarified requirements for an extension of the deadline for beginning production in both §§ 203.35 and 203.44. These changes do not alter the substance of any of the moved provisions.

C. Comments Not Leading to Rule Modifications

The following discussion is arranged into 10 issue topics for purposes of organizing responses to comments for which no changes in the rule were made. The oil and gas industry letters generally objected to 3 parts of the proposed rule: (1) The price threshold level, (2) a sunset for royalty relief in the 200 to 400 meter water depth, and (3) the ability of only the first deep or ultra-deep well on a lease to earn the RSV. Both the industry and environmental representatives submitted comments on (4) the fiscal cost of the proposed rule. The letters from the environmental organizations also expressed concerns about: (5) the propriety of any royalty relief in Alaska, (6) the analysis accompanying this rule, and (7) the competence of MMS to administer royalty relief provisions. The substantive private citizen letter pointed out possible problems with: (8) price thresholds in connection with royalty in-kind, (9) the rule's information collection provisions, and (10) estimates of the size of the incentive's effect. The next section reviews and responds to the particular comments in each of these categories, as well as the detailed API recommendations not adopted.

1. *Price Threshold Level:* Industry comments on this issue ranged from statements that the proposed price threshold level is too low, that the threshold should be consistent with the one in the existing regulation, that it ought to be even higher than the threshold in the existing regulation, or that setting an appropriate threshold should have no connection to the lack of a sunset date.

The most direct criticism about this issue is reflected in the following quote from Chevron.

> MMS's proposed price threshold of $4.47 per MMBTU is too low and will have the effect of nullifying the stipulated royalty relief incentive * * * the new deep gas royalty relief incentives [will be given] little or no value in making lease acquisition and drilling decisions. The effect of establishing a low price threshold in the proposed rule circumvents Section 344's purpose.

The MMS considered but declined to set a higher price threshold for several reasons. In general, high gas prices provide all the incentive needed for additional production. Moreover, Congress established this gas price threshold for a previous royalty relief program that it mandated for pre-existing deepwater leases in the GOM (DWRRA), albeit when market prices were much lower than now. Given the discretion afforded the Secretary of the Department of the Interior by Congress to engage in this rulemaking, MMS has decided to adopt that previous gas price threshold, concluding that an across-the-board royalty incentive is not necessary inasmuch as current prices are far above historic levels. We note, however, that we believe this new royalty relief provision still has value as a cushion against a possible gas price collapse after drilling decisions have been made.

A variation of this criticism of the proposed level of the gas price threshold is the recommendation to use the same price threshold as set in the existing deep gas regulation:

> * * * our recommendation is that at minimum the existing rule's $9.88 per MMBTU base price threshold (adjusted over time for inflation) be adopted as the applicable price limitation (API).

This argument for consistency is not compelling. The high price threshold in the existing program was adopted in connection with a fixed sunset date, a feature not included in the statute in connection with the ultra-deep well incentive, the most significant part of the new program. Indeed, the existing deep gas incentive will begin to phase out in less than a year. Further, technological capabilities have improved and price-cost margins have increased since the existing regulation was issued. Finally, the lower price threshold coincides with the gas price threshold level set for deepwater leases MMS issued from 2002 to 2004 and since 2007. As such, this level of gas price threshold applies to the large and growing number of deepwater leases issued under that incentive. A deep gas price threshold that matches one used in deepwater will mitigate inconsistency between the deep gas and deepwater relief programs. The enhanced consistency of incentive terms across different leases will reduce confusion in the long run after the existing deep gas program has expired and will reduce the distortion in lease development decisions associated with different likelihoods of realizing royalty relief. Use of this same price threshold for the new ultra-deep gas drilling incentive thereby improves consistency of market terms for gas produced under both of the major long term OCS royalty relief programs that have gas price thresholds.

Related comments advocated an even higher price threshold.

> The price threshold of $4.47/MMBtu * * * is substantially less than the price threshold applicable to royalty suspension volumes under the existing rule * * * rather than raising the threshold to respond to the fact that it costs more for companies to make the investment into these frontier areas than it did before, the MMS has instead gone in the opposite direction by proposing an extremely low threshold (NOIA, et al.).
>
> MMS further justifies the lower price threshold based on the lack of response to deep gas relief to date. The current relief, with a $9.88/mmbtu price threshold, did not result in significant deep drilling because of the high cost and technical risk associated with drilling at these depths. The historical lack of response under the $9.88/mmbtu [threshold] logically argues that an even higher price threshold than $9.88/mmbtu may be necessary to entice lessees to take on the financial and technical risks of ultra-deep drilling (API).

These arguments are not persuasive. The commenters did not provide evidence that drilling costs for ultra-deep wells have gone up as much or more than the price of natural gas. Further, relating price thresholds, under which royalty relief is realized, to cost indexes would tend to reduce normal incentives to resist or avoid increases in drilling costs. Also, matching price thresholds to market conditions would increase the amount of royalty relief or, in other words, the subsidy or transfer from taxpayers to industry at the same time that industry's profits are rising. Finally, the higher price threshold did not cause the lack of response to the existing deep gas relief. On the contrary, because it was not exceeded and probably not expected to be exceeded, it allowed the full enticement effect of the incentive to occur—yet the incremental drilling results have been small.

A final price threshold issue concerned its connection to a sunset date.

> MMS justifies the lower price threshold level based on the lack of a sunset provision. The lack of a sunset provision for ultra-deep drilling is necessary given the immense technical challenge posed by these wells. The need to develop experience and technology will require long lead times, making a sunset provision impractical. The lack of a sunset provision is appropriate for ultra-deep wells and is not a sound reason for a lower price threshold (API).
>
> The price thresholds must be set through economic modeling to establish the price at which lessees no longer need an incentive to drill deep or ultra-deep gas wells. Frustration over the ability to establish a sunset for royalty relief hardly meets that standard and is simply further evidence that, through this proposed rule, the MMS is seeking to undermine Congress' intent to provide new incentives for deep and ultra-deep gas production (NOIA, *et al.*).

In fact, the statutory silence with respect to a sunset date restricts policy flexibility. A sunset would have allowed for automatic ending of a policy, such as was implemented in the existing deep gas incentive regulations, in which a price threshold in conjunction with other program elements beforehand appeared in step with market conditions but then performed poorly. Congress chose, in section 344 of the statute, to set no sunset; but by authorizing the Secretary to limit relief based on market prices, it did impose the responsibility on the Secretary of containing the loss from a policy that has been considerably less effective than anticipated. The price threshold is the only instrument the Secretary has to perform the important task of potentially saving taxpayers hundreds-of-millions of dollars in forgone royalties to lessees with deep gas wells that would have been drilled even without the incentive. Further, long term gas price forecasts change over time, so it is not possible to fix a single optimum gas price threshold for the entire period over which gas may be produced under the ultra-deep gas incentive. If we retained the ability to adjust the price threshold as conditions warrant, we would add uncertainty that undermines the ability of companies to make the long term plans necessary to develop challenging prospects. Therefore, we judge selection of a fixed, if conservative, price threshold that balances an added incentive for ultra-deep drilling with fiscal prudence over the long term to be the best price threshold policy in the absence of a sunset provision and a weak response to existing incentives.

2. *Sunset date in 200 to 400 meters:* This issue received recommendations that a sunset is not required by the statute; that a sunset contravenes the statute; and that, if necessary, a rolling sunset date should be used.

One objector to a sunset provision appealed for a less rigorous interpretation of the statute.

> * * * MMS has chosen to adopt the sunset concept in the new implementing proposed royalty relief regulations for 200 to 400 meter water depth to match the current regulations. While adopting the existing regulations is mandated by Congress, a reasonable person could interpret * * * that the Secretary should use the current methodology in determining well depth and completion interval restriction along with relief volume factors as complying with the intent of Congress. The time limitation is not stipulated * * * an argument could be made that the time limitation in the current regulations is not a part of the "methodology" the Secretary must use in implementing the application of the existing regulations to leases issued in water depths from 200 to 400 meters (API).

Nevertheless, we consider the sunset to be an essential part of the methodology because it affects the nature of the appropriate relief terms. The sunset forecloses an indefinite duration for what might turn out to be an ineffective or even wasteful policy. Under that protection, the size and breadth (e.g., relief for unsuccessful wells, sidetracks, and subsequent deep wells) of the incentive can be made more enticing than otherwise.

Another objector suggested:

> * * * the MMS's proposed May 3, 2013 sunset provision * * * also contravenes Section 344's purpose of encouraging deep gas production. Because of the complexity and expense involved in deep gas exploration, especially where acquisition of new leases is involved, in many cases it will likely take lessees many years to bring new deep gas wells to production. * * * the cost reduction incentive Congress created * * * is negated * * * (Chevron).

The fairly short sunset provision is intended to reward expedited development of deep gas production from this most quickly accessible alternative. Longer term, alternative sources of natural gas such as deepwater fields, LNG imports, and Alaskan reserves have time to develop and reduce the burden on supplies from shallow water leases.

As with the price threshold, commenters recommended a flexible alternative if sunset dates must be used.

> * * * we recommend MMS reconsider implementation of the sunset provision by either eliminating it or tying the sunset provision to the commencement of production from a qualifying well. Instead of a specific sunset date (i.e., May 3, 2013) MMS could use five (5) years from the date operations on a qualifying well are completed (API).

Yet, while a floating date, such as 5 years after operations on a qualifying well are completed, may facilitate installation of infrastructure and arrangement of transportation, the starting event is too vague a standard to enforce effectively and efficiently. More importantly, this rolling sunset still leaves an endless program cessation date. Not only is such a formulation likely to be very costly in terms of forgone revenues, but it frustrates the original intent of deep gas royalty relief—to accelerate deep depth drilling.

3. *Relief for only the first ultra-deep well on a lease:* This provision elicited comments about its rationale, the legitimacy for the limits it creates, and the chance that the new rule could provide less relief for a qualified well than would have the existing rule.

One objection to this provision urged a departure from the logic of the existing incentive.

> MMS has failed to provide any rationale for its decision to deny granting 35 BCF of royalty relief for a second well on a lease. The agency has chosen instead to unilaterally and arbitrarily thwart Congress' expressed intent to incentivize [sic] ultra-deep production by denying royalty relief for ultra-deep wells on leases with existing deep wells or ultra-deep wells regardless of the situation that exists on the lease (NOIA, et al.).
>
> The rule fails to explain why the existence of a reservoir at 15,000 feet in any way reduces the cost or risk of drilling an ultra-deep well with a target depth of 22,000 feet. Similarly, the rule does not explain why an ultra-deep well producing from a reservoir on the east side of a lease reduces the cost or risk of drilling an ultra-deep well to produce from a different reservoir on the west side of the lease (NOIA, et al.).

This charge fails to acknowledge that the proposed rule continued the same principle found in the existing deep gas relief rule of granting less or no relief to subsequent deep wells on the same lease. The rationale for this principle is that the first deep well on a lease reduces risk by establishing that hydrocarbons exist and are producible from deep depths from the geology found within the relatively small area covered by the lease. Also, production from the first deep well on the lease reduces the cost for subsequent deep wells by financing the acquisition and installation of any necessary production and transportation infrastructure for deep production in the vicinity of the subsequent well.

Related comments suggest that the rule is more restrictive than it actually is:

Limiting royalty relief to 'ultra deep' wells that are the first deep gas wells to produce on a lease, however, flouts Section 344's intent by arbitrarily eliminating the cost reduction incentive of royalty relief for an 'ultra deep' well that merely happens not to be the first deep gas well to produce on the lease. * * * we recommend MMS not limit royalty relief to 'ultra deep' gas wells that are the first wells to produce on a lease, but rather allow relief to be applied to new deep gas wells whenever they are drilled on a lease after implementation of the rule (Chevron).

The proposed rule departed from the structure of the existing rule only where the statute provided no other reasonable choice. As the proposed rule explains, language in the statute requires an all-or-none choice, i.e., granting either full relief or no relief to sidetracks and subsequent ultra-deep wells. The MMS chose not to double or more the size of relief for a short sidetrack or for a second well on the lease just because it happens to be an ultra-deep well. Moreover, the commenter's argument ignores the fact that the additional incentive will apply to other qualified wells on the lease. The first deep or ultra-deep well on a lease earns a royalty suspension volume for the lease. If the first deep well is an ultra-deep well, it earns a larger royalty suspension volume than under the existing rule, as directed by Congress. Subsequent deep or ultra-deep wells and shorter sidetracks to deep depths on the lease share that larger relief. Moreover, the decision on the second ultra-deep well is not arbitrary because it follows the pattern of the existing rule. The second well benefits from the presence of the first deep producing well on the lease, and therefore, needs less incentive.

Another comment highlights a quirk resulting from our cautious approach to the all-or-none choice created by the statutory language:

The proposed rule would in many cases provide less royalty relief than is currently available under the existing rules. The rule would result in wells drilled at greater depths earning the same or less of an incentive or no incentive at all. Additionally, the rule would lead to wells drilled between 200 and 400 meters possibly earning less of an incentive than wells drilled in less than 200 meters. Under the existing rule, a lessee with an existing well drilled to a depth of 15,000 feet would receive an additional 10 BCF of suspension volume for an ultra-deep well drilled on the lease. However, under the proposed rule, for most leases, the lessee will receive no additional royalty suspension volume for drilling a second, ultra-deep well on a lease that already has a well drilled to 15,000 feet (NOIA, et al.).

While technically possible, experience indicates that few if any actual cases will result in a well earning less royalty relief under this rule than under the existing rule. For that peculiar situation to occur, an ultra-deep well would have to be spudded on or after May 18, 2007, and put into production on a lease that already has a well producing from at least 15,000 feet deep. Further, this event must occur on a lease partly or entirely in less than 200 meters of water during the slightly less than 2 years before the expiration of the incentives under the existing deep gas rule on May 3, 2009. The MMS records indicate that only 2 leases have met those conditions during the 4 years after the existing incentive became available on March 26, 2008.

For an ultra-deep well to earn a smaller amount of relief than a deep well completed at a lesser depth (18,000 to 20,000 feet) on a lease, both the ultra-deep and less deep wells would have to be spudded after May 17, 2007, and put into production on a lease that already has a well producing from at least 15,000 feet deep. The MMS records show no case, during the first 4 years after the existing incentive became available, of a well between 18,000 and 20,000 feet deep that was spudded and began production on a lease with a producing well at least 15,000 feet deep. On leases partly or entirely in less than 200 meters of water, this unprecedented event must occur during the slightly less than 2 years between issuance of the proposed rule on May 18, 2007, and prior to expiration of the incentives under the existing deep gas rule on May 3, 2009. On leases in 200 to 400 meters of water, both wells must be spudded and put into production during a longer period, from May 18, 2007 and before May 3, 2013. However, since the 200 to 400 meter water depth interval contains only about 6 percent of the number of active leases as does the 0 to 200 meter water depth interval, the chances of this event occurring in the deeper water interval appear even lower than in the shallower water depth interval.

A very limited number of non-symmetric cases could occur across water depth categories. Leases in 200 to 400 meters of water became eligible on May 18, 2007, to earn the same amount of relief for drilling a deep or ultra-deep well, as would a lease in less than 200 meters of water, with one exception. The exception applies to leases in partly or entirely less than 200 meters of water and issued during 2004 and 2005. These leases have deep gas royalty relief terms from the existing rule explicitly stated in their lease instruments. To earn relief that a lease in 200 to 400 meters of water could not, the exception lease located in 200 meters of water or less and issued in 2004 or 2005 would have to have production from a well at least 15,000 feet deep and then start production from an ultra-deep well, all within the abbreviated period prior to May 3, 2009.

A final criticism in this vein is that it is possible for an ultra-deep well to earn less relief than a deep well completed to a lesser depth:

In the few instances where the proposed rule would provide an incentive for a deep sidetrack or second well on a lease, the proposed rule is still nonsensical. As an example, if a company drilled a well to 15,000 feet under the old rule and received a suspension volume of 15 BCF, and then drilled a new well under this rule to 18,000 feet, the company would receive an additional 10 BCF. However, if that same company drilled a new well that was deeper, to 20,000 feet, it would not get the additional 10 BCF, but instead would get no suspension volume at all for that well. Hence, the rule is actually a disincentive to drill to deeper depths. This interpretation of the statute runs counter to the will of Congress (NOIA, *et al.*).

As already noted, this particular circumstance has not yet happened over a period twice as long as remains for it to happen. Regardless, the proposed rule is not a disincentive to drill to deeper depths. It provides the full 35 BCF directed by Congress for an ultra-deep well if the drilling activity pioneers production on the lease at deep depth with its unique temperature, pressure, and corrosion conditions. If the ultra-deep well is a subsequent deep well or a short sidetrack, the proposed rule provides no additional relief, but the second or sidetrack ultra-deep well still share any remaining relief available to the lease. The problem is that the statutory language dictates this all-or-none situation by precluding the opportunity to provide relief at a reduced level that is more appropriate for a subsequent ultra-deep well or short sidetrack. Thus, while our rule could have avoided this odd and unlikely situation, the statute would have forced adoption of a much less defensible policy position resulting in the granting of far greater royalty relief than would be warranted.

4. *Fiscal costs of the relief:* This issue drew opposing comments about the loss of Government revenue due to the royalty relief in this rule.

One of the industry comments conveys a false impression that categorical or ''incentive based'' royalty relief may be costless to taxpayers:

Under the 'need' based relief program, lessees must prove that their oil and natural gas related projects require some form of royalty reduction or suspension to make their project economic. * * * 'Incentive' based royalty relief has the purpose of enticing potential lessees to invest in oil and natural gas projects knowing additional financial benefit could be derived should a commercial discovery be made and subsequently oil and/or gas produced. * * * Considering the fact that most leases issued are not drilled, the Federal Government collected significant revenue in the form of bonuses and rentals from these new leases, some of which would probably not have been leased without royalty relief. * * * Congress recognizes the benefits associated with 'incentive' based royalty relief programs by its passage of EPACT [the Energy Policy Act of 2005] (API).

However, categorical royalty relief results in forgone royalty, from deep wells that would have been drilled and produced even without the royalty relief. Thus, such royalty relief is unlikely to be a net revenue generating program for the Federal Government when applied to already existing leases that have no more bonus bid to pay. For new leases, relief largely serves to speed-up leasing by suspending royalties that would have been collected later when the lease would likely be sold after the emergence of better technology, higher prices, or lower costs. Moreover, even though higher bonuses would be expected in the presence of royalty suspensions, we note that bid premiums associated with the categorical relief provided to DWRRA leases proved to be modest at best.

Comments by environmental groups on our proposal to apply discretionary, need based royalty relief procedures in Alaska indicated concern about the high fiscal or administrative costs of such a program:

* * * MMS needs to ensure that it has adequately scrutinized all of the regulation's effects to the public interest both in protecting the environment of the OCS and adjacent coastal environment, and to ensure that the public yields [receives] a fair price for the exploitation of the oil and natural gas resources from federal OCS waters. * * * Please provide the analysis used to determine that there would be 'no negative effect on federal revenue' from this rulemaking. If there is royalty relief granted, those revenues will not come to the federal treasury. * * * Certainly, if MMS must respond to requests for relief for an additional vast area in Alaska encompassed by four different planning areas (at this time), and then must audit and account for the relief granted, it is illogical to assume that MMS will not face costs in implementing this section, and that there would be no economic effect. * * * Would this royalty relief for the Alaska OCS have any implications for revenue distribution from leases in the 8(g) zone? These were not addressed by your proposal (NAEC, *et al.*).

This rule proposes to apply a royalty relief process to offshore Alaska leases that is specifically designed to avoid unnecessary royalty relief. Projects that are forecast to be profitable paying full royalty would not get relief, while those not anticipated to be profitable while paying full royalty are unlikely to proceed to development and production unless some modifications to royalty terms are made. Projects that do not go into production generate no royalty revenue for the Federal treasury. With royalty relief, production in excess of the suspension volume will generate royalty revenue on such projects. Thus, we do not expect negative effects on Federal revenue from our discretionary case-by-case royalty relief program in Alaska.

While MMS may face administrative costs, no net program costs should result since relief applications carry a user-fee designed to cover the cost of review. The MMS determines how much royalty relief, if any, would be needed and would provide only the amount of royalty suspension needed to change an anticipated decision not to develop. Any production beyond that suspension amount promises royalty receipts that would not have materialized otherwise. Finally, the rule will not adversely affect expected section 8(g) revenues, since the process for approving royalty relief seeks to ensure that any production occurring under royalty relief would not have occurred without that relief. Thus, we do not anticipate that any royalty revenues, including those subject to section 8(g), would be lost as a result of this program.

5. *Propriety of Royalty Relief in Alaska:* Comments on this issue question how and even whether royalty relief should be offered in Alaska.

One sentiment seems to underlie many of the comments from both environmental organizations:

Royalty relief is not appropriate for application in Alaskan waters, and the proposed rule provides no adequate description of the proposed scenario for the discretionary application of royalty relief within Alaska OCS Planning Areas: The **Federal Register** Notice for RIN 1010–AD33 * * * includes virtually no detailed discussion of how, where, and under what circumstances Secretarial Discretion will be applied to expand royalty relief into Alaskan waters. * * * It is therefore premature * * * for MMS to be prescribing terms and conditions for royalty relief in these regions (DoW).

This and several related comments reflect confusion about what the proposed rule adds to existing royalty relief for leases offshore Alaska. As it happens, most offshore Alaska leases already have categorical royalty relief under the terms with which they were originally issued. Section 346 of the Energy Policy Act of 2005 gives the owners of other offshore Alaska leases a chance to request relief but MMS will grant relief only on a demonstrated economic need basis. Further, the royalty relief covered by these regulations has been available to offshore Alaska leases since the statute was enacted in 2005. This rule cannot change that fact, but it can and does establish a standardized process for the lessee of a lease offshore Alaska to follow in submitting a complete application for relief. It also explains how MMS will evaluate whether that application would result in approval of some royalty relief.

Related comments do not take into account the existing rigorous qualifying procedures set forth in regulations starting at 30 CFR 203.60 that more fully define the relief process being applied to Alaska by this rule:

MMS procedures for granting Alaska OCS royalty relief appear to be arbitrary and not founded on any economic modeling, or have any specific criteria for Alaska that it will use to base its decisions. * * * No criteria are discussed specific to the Alaska OCS regarding MMS's basis for granting royalty relief on leases. * * * MMS needs to ensure that its decision to grant it [royalty relief] is not arbitrary, and describe the basis upon which it will determine whether or not a project is 'economic' or 'uneconomic' without the relief. What information will the applicant need to provide? There may be unique information needs for the Alaska OCS but MMS does not provide or require these. Why shouldn't the applicant have to provide its assessment of the profit it would take out of the leases with and without the royalty relief requested (NAEC, *et al.*)?

The proposed rule discussed only those parts of the existing regulation that are being changed to include leases offshore Alaska. The other parts of existing regulations that will apply to leases offshore Alaska that seek relief are not being changed by this rule, including those that detail how Secretarial discretion will be exercised, can be found in 30 CFR Part 203. The CFR sections referenced in this rule (see 30 CFR 203.60, 62, 67–70, 73, 76–79) detail the extensive information and profit assessment the applicant needs to provide and the process MMS would use to determine if a project requires relief to be economic. In general, the process for evaluating and granting royalty relief is based on an individual analysis of the proposed project, which allows inclusion of any condition affecting project economics that is specific to the lease and to Alaska.

6. *Analysis accompanying rule:* Comments in this area emphasize doubts about the adequacy of economic and environmental impact analysis behind the rule.

One line of comments indicates a lack of awareness of the extent of the analysis that was associated with this rulemaking:

* * * [I]t is incumbent on any proposed rule for expanding royalty relief to include a full and documented economic impact analysis of the expanded royalty relief program being proposed, both in the Gulf of Mexico as well as in Alaskan waters. This economic impact analysis must include a full delineation of the effects of market price on the application of royalty relief in any waters to which it may be applied (DoW).

MMS did not conduct any economic analysis projecting the total loss of potential royalties to the taxpayer nationally, or from the new Alaska OCS royalty holiday. MMS does not make clear in the rule-making the maximum loss of royalties that could occur. * * * MMS did not evaluate whether economic conditions such as the greatly increased price per barrel of oil since 1999 would significantly change the situation now and whether this could lead to substantially increased losses to the public. * * * MMS states that 'this rulemaking raises novel legal or policy issues' (72 FR 28409) yet does not discuss these legal or policy issues in any depth with respect to Alaska (NAEC, *et al.*).

The proposed rule included the full suite of economic analysis required by OMB and under various laws, beginning on page 72 FR 28409. A more extensive analysis of the effects of section 344 in the GOM is referenced in the rule and is available on the MMS Web site at: *http://www.mms.gov/econ/PDFs/2007AddendumDeepGasEA%20_2_.pdf.* Further, the expansion of the royalty relief program implemented by this rule is mandated by statute. In fact, the rule grants no more relief than the statute compels, despite the flexibility of the statute that would allow MMS to offer potentially much greater amounts of relief. The novel policy issues in the proposed rule arise in connection with section 344's expansion of the categorical deep gas royalty relief program in the GOM, not with section 346's inclusion of Alaska leases in a long established pre-production royalty relief process that relies on case-by-case analysis of a project's economic need for relief.

This rule does not mandate any royalty relief be granted in Alaska, nor does it automatically provide relief in specified amounts. Whether relief is granted in Alaska, and how much to grant, would be based on careful evaluation of any complete application. Accordingly, there should be no lost royalties under the proposed rule's implementation of section 346. The process prescribed invokes an evaluation and follow-up procedure that is not intended nor designed to grant royalty relief unless production would not occur otherwise. If no production would have occurred without royalty relief, no royalty would have been generated to lose. Furthermore, the inclusion of price thresholds both in the categorical relief under section 344 and in the process invoked by the rule for section 346 relief will preclude royalty relief at greatly increased prices for oil or gas. It even may result in extra royalties if the promise of potential relief manages to encourage production which would not have occurred otherwise.

Other comments raise an environmental concern with the proposed royalty relief:

* * * MMS needs to analyze the environmental impacts of this royalty relief in order to determine if the subsidy is in the public interest. For example, if taxpayer help is needed in order for an oil field to be developed in sensitive Alaska waters that threaten subsistence, or endangered species, marine mammals, polar bears, migratory birds, etc., we question that such action is really in the public interest. * * * The royalty relief issue was not evaluated in the Beaufort Sea Sale 186, 195, or 202 Environmental Impact Statements, or the current Chukchi Sea Sale 193 EISs, even though these subsidies may apply to those leases. Therefore, if MMS states that the fields for which it would grant royalty relief would not be developed without the subsidy, it must be anticipating additional oil field development beyond what was described in those environmental reviews, and therefore it cannot grant this relief for those leases due to the lack of this issue being addressed, or alternatively, MMS must provide supplemental environmental review prior to granting any royalty relief for those leases from prior sales in Alaska (NAEC, *et al.*).

These comments do not take into account that the original lease issuance grants the lessee the right to explore and then develop discoveries after full consideration of environmental impacts and any potential threats to local species. Congress decided to supplement this right in section 346 by providing MMS with the authority to consider royalty relief as a means to ''promote development or increased production on * * * non-producing leases * * *'' The relief process implemented by this rulemaking applies to tracts located offshore Alaska that have been issued in previous lease sales or will be issued in future sales. The lease sale process has or will consider the effects of potential exploration and development activity on biological resources in that area. In addition, environmental impact studies cannot predict with certainty the geologic characteristics of specific fields or which ones will be developed. Pre-sale environmental reviews, completed at this early stage of Alaska lease exploration, only estimate the potential size and possible pace of development. Also, MMS provides National Environmental Policy Act analysis on individual development and production plans. Royalty relief does not necessarily affect that estimate significantly for the aggregate of all fields, in part because it is typically the smaller fields that could benefit from relief. The sum of production from smaller fields whose development is made possible by relief is likely to be a small part of the aggregate production estimate for the whole area. Moreover, the royalty relief program envisioned only deals with specific marginal fields after exploration has clarified the characteristics of the subject field, not the whole area.

7. *Competence of MMS to administer royalty relief provisions:* Comments in this area oppose the relief in this rule on the grounds that it may not be managed properly.

Several comments envisage recurrence of a problem recently discovered in another part of the MMS royalty relief program:

Past errors of management of the royalty relief program provide no basis for expanding the same program based upon the same categories of misassumptions and data gaps (DoW).

There have been major problems with the existing Gulf of Mexico deep-water royalty provisions * * * and the House of Representatives passed an energy bill, H.R. 6 which repealed the EPCA Section 346 * * * This section is very controversial, * * * The Government Accountability Office has raised questions of the financial impact of MMS's deep water royalty relief program * * * However, MMS's draft rulemaking does not explain in detail how the past problems will be avoided by the new regulations, nor how it will avoid new problems by the extension of the program to Alaska (NAEC, *et al.*).

The very source of the problems in the deepwater categorical royalty relief program in the GOM is precluded by the inclusion in this rule of a default price threshold in the changes to the regulations proposed by this rule. The rule applies default price thresholds to royalty relief for all future GOM leases (*see* §§ 203.36, 203.48, 203.78, and 260.122) and explains that this action will eliminate any omission of a price threshold for leases with royalty suspension volumes in future lease sales (*see* 72 FR 28409). Further, the royalty relief process applied to offshore Alaska leases by this rule is designed to ensure that no unnecessary royalty relief will be granted. This process has been refined through more than 10 years of use, and is applied to existing leases in a case-specific discretionary relief program that is very different from the one for leases in the GOM issued under the DWRRA.

Other comments worry about the way the price threshold would be set:

MMS needs to describe the price thresholds for all the royalty relief provisions and for Alaska leases specifically, including how it will determine this basis and what the expected results are. Failure to issue regulations or leases with proper price thresholds led to a ''costly mistake and loss of billions in royalties in the Gulf of Mexico, * * * there is no evidence that MMS has adequate systems in place to assure a fair system is in place that does not harm the U.S. taxpayers generally * * * (NAEC, *et al.*).

Price thresholds set in lease documents are chosen at the time of the lease sale and the process by which they are originally set is explained in the associated decision documents. This rule establishes default price thresholds for royalty relief for GOM leases in the regulations, which are applied should the lease documents not specify another price threshold. Moreover, MMS has adopted many new internal control procedures apart from this rule to ensure that the previous error does not occur again. In the past 8 years, it never has. When price thresholds are established as part of the process for evaluating whether an Alaska lease needs royalty relief, the determination of the applicable price threshold will be explained in that decision. In general, that process will include judgments made at the time of the application about projected oil and gas price levels and volatility, development costs, and other factors influencing project profitability.

Another assertion is that this rule is premature:

* * * The apparent rush by MMS to publish this proposed rule, even as Congress now revisits the issue of royalty relief and its role in denying fair market value to the federal treasury, seems to fly in the face of legislative intent. It would be wholly consistent with present congressional deliberations to abate any final action on this proposed rule until new legislation, now pending, supersedes the 2005 Energy Policy Act and clarifies legislative intent on the issue of royalty relief (DoW).

Ongoing Congressional deliberations do not supersede existing law and any new laws that may be passed will not negate the need for this rule to address the requirements of the Energy Policy Act of 2005. First, there is no assurance repeal will become law. Second, even if section 344 is repealed, this rule still must be promulgated because its terms apply to 605 leases issued in the 2006 and 2007 lease sales plus about 900 issued under lease sales in 2008. Lease documents for those sales include language granting lessees the royalty relief provided by the still effective statute, subject to the implementing MMS rule. This rule sets up the specific terms and conditions on this relief that may not otherwise be enforceable, and at the very least, will remain ambiguous until the final rule is published. It is also worth noting in relation to the stated ''rush by MMS to publish this rule'' that MMS's thorough review and analysis have resulted in issuing a rule more than 2 years after the deadline set by section 344 of the statute in part to ensure the fiscal integrity of the adopted program.

A related comment laments the need to rely on MMS evaluations:

Unfortunately, due to the proprietary nature of economic information for oil and gas exploration, development, or production projects, it means that even if the MMS does obtain such information, the public will not have access to it to evaluate the fairness or adequacy of MMS's decisions over the royalty holidays that are granted (NAEC, et al.).

Release of proprietary information would violate rights of companies to protection of commercially sensitive information. To compensate, MMS employs objective technical experts, a sophisticated and rigorous analytical approach, and a robust review process to evaluate fully an applicant's economic need for royalty relief. That capability is used to fulfill the OCSLA and DWRRA charge to the Secretary (delegated to MMS) to consider the granting of royalty relief to increase production or promote development of oil and gas resources, while balancing protection of human, coastal, and marine environments, ensuring the public a fair and equitable return on OCS resources and maintaining free enterprise competition.

8. *Incompatibility of price thresholds and royalty in-kind:* One comment raises a possible burden this rule places on leases that pay royalty in-kind (RIK) instead of in-value. That burden has to do with the need to pay back royalty relief in-value after the year because the average gas price exceeded the price threshold.

* * * The proposed rule and support documents are silent on RIK * * * This places a burden on the lease owner depending on violent fluctuations of the gas market price. This burden is the staffing up or down in order to meet the requirement associated with royalty in value. I suggest a more economic process would be that the MMS take possession of the potential RIK product and market it. Then, based on market price and price threshold, send the proceeds of the RIK to the lease owner or the U.S. Treasury as appropriate. This provides efficiency to both lease owners and MMS (Tupper).

Mr. Tupper's suggestion for resolving the issue of payback of royalties taken in kind is not practical. This is the case because the timing of original RIK collections and sales does not correspond to the timing of when payback is determined and the amounts due are calculated. Regardless, lease owners operating under an RIK arrangement are not likely to have either an administrative or fiscal problem related to payback of RIK royalties. For one thing, MMS generally does not take royalties in kind from deep gas wells because of the uncertainty of whether royalties are due from those wells. In situations where MMS did take royalties in kind from deep gas wells that qualify for a royalty suspension volume, the MMS procedures for valuing payback amounts for royalty taken in kind would be included in an agreement with the operator. Accordingly, if the price threshold is determined by MMS not to have been exceeded on a royalty relief lease after the period for which MMS has taken royalties in kind from that lease, MMS would refund royalties to the operator based on the monthly values MMS received for that production when taken in kind. On the other hand, if the price threshold is determined by MMS to have been exceeded on a royalty relief lease after the period for which MMS has taken royalties in kind from that lease, no payback is necessary and the operator would have met its royalty obligation by delivery of royalties in kind during the period. The MMS decisions on whether or not to take production in kind are based on the economics of each property and whether doing so is favorable to the Government.

9. *Redundant information collection:* A procedural comment suggests MMS is unnecessarily requesting redundant information from OCS operators:

* * * MMS is already collecting most if not all of the information needed as a routine business * * * the first step [in qualifying for deep gas royalty relief] is to notify the MMS Regional Supervisor for Production and Development of intent to begin drilling operations. The MMS is independently informed of this intent with the submission of the Application for Permit to Drill which is via Form MMS–123 * * * MMS is proposing a new information collection process with significant overlap with the information collection already in place.

* * * The paradigm of the proposed rule is that the lease operator needs to figure out if a well may be eligible for an RSV and then request it. The MMS validates the application and sends a confirmation back to the lease operator. I suggest that the correct approach is that MMS use its existing information collection data stream to determine if an RSV is available under the rules and inform the lease operator that RSV is granted (Tupper).

This suggestion glosses over a subtle but critical aspect of the rule. The categorical relief in this rule is intended to serve as an incentive for a lessee or operator to drill deep and ultra-deep wells. The notification initiating the relief process authenticates that the relief is an ex ante part of the decision to drill, rather than an ex post windfall, which it might be if MMS initiates the process. Also, since companies are already providing most of this information, the administrative burden of making a copy to demonstrate response to a valuable incentive is minimal. Finally, normal lags in the Government's data entry and query process might delay relief and increase the chances that an erroneous collection or avoidable refund step might be launched if the critical wells are not flagged ahead of time by the private sector for relief consideration.

10. *Estimates of the size of the incentive's effect:* One comment faults an assumption made in the analysis behind this rule:

* * * The supporting document *Programmatic Effects of the Deep Gas Incentives in the Energy Policy Act 2005* * * * makes an assumption of a constant reservoir size * * * I believe this assumption is suspect * * * Gas Fields in water depth of 200 meters or less * * * have the following statistical attributes: * * * This surrogate data suggests the size of discovery is declining with time. This is not an arcane statistical issue, but rather key attribute of the effectiveness of the policy. Are the 10 to 12 percent of the wells drilled which the study indicates are associated with royalty relief incentives located in average sized reservoirs or are they located in smaller reservoirs that are only economic with the royalty relief? If the MMS assumption on reservoir size is correct, then around 10 percent of the production is due to the incentive. If the reservoirs are much smaller then the share of production due to incentive will be corresponding smaller. Size does matter (Tupper).

This observation serves to reinforce the validity of the conservative implementation policy adopted in this rule. The estimated 10–12 percent effect on well drilling cited by the commenter is associated with the provision of suspension volumes in the absence of price thresholds. Once price thresholds are introduced, the estimated original effects on drilling (and, equivalently, production) are reduced considerably, and are then estimated to represent one to three percent of the new total deep drilling and production levels, which include both market price and net incentive effects. Thus, our analysis is already very conservative with regard to estimates of programmatic effects attributable to the deep gas royalty relief incentives. Moreover, there are some grounds for support of the constant discovery size assumption even if one focuses on the strict numerical results alone, rather than on their relative magnitudes and policy implications. This is the case because most of the incremental effects estimated for this analysis from royalty relief occur for ultra-deep wells, of which very few have been drilled outside the unique Norphlet trend offshore Alabama. Thus, it may well be that the larger discoveries in the ultra-deep zone apart from the Norphlet trend have yet to be made, in which case the average field size still to be discovered could be greater than postulated in our analysis. In that not unlikely scenario, use of a constant discovery size would mitigate somewhat our underestimate of future incremental effects from the royalty relief incentive.

Miscellaneous issues: A number of technical requests in the API comments indicate misunderstandings about some of the features of this rule. As a result, we will not make the changes requested:

- The request to add limits on the dates when the host leases were issued to the definition of phase 1 ultra-deep well is not generally appropriate since such a well can be located on most existing shallow water leases regardless of when the lease was issued. Other than the relatively few leases excluded by virtue of having been issued with royalty relief under DWRRA (see § 203.40), the only date that matters is when the well was spudded and began producing.
- The request to change the definition to allow a qualified well to be drilled into a reservoir that has been penetrated on an adjacent or other lease neglects a condition unique to the variant of deep gas relief that we granted to leases issued between 2001 and 2003, but discontinued for leases issued later. For leases issued in those years, lease terms authorized relief only for a well drilled into a deep gas reservoir that has not produced on any current lease. Thus, we retain that condition for a qualified deep well on a lease issued between 2001 and 2003.
- The request to cite in § 203.2 those later sections that describe what must be done to demonstrate an expansion or development project is uneconomic under the regulations would only duplicate our citation of the relevant CFR sections in the parentheses at the end of the sentences in the third column of the table.
- The request to specify that a sidetrack measured depth must be 20,000 feet TVD SS would confuse diagonal drilling length with vertical depth subsea.
- The request to add a deeper bound to the water depth range specified in §§ 203.34 and 203.43 misses the fact that no such bound is needed because these two sections deal with situations where the royalty relief in this rule does not apply and deep and ultra-deep gas royalty relief never applies to leases in water deeper than 400 meters.
- The request to add another example of a situation, such as equipment failure justifying a delay in the sunset date is not necessary as those listed are intended to be just illustrations and not an exhaustive list. Other situations than those listed may be a good reason for extending the deadline for production start in individual cases.
- The request to add wording that does not count gas production which is not normally royalty-bearing (fuel gas) against the RSV is not practical. As we explained in the original deep gas rule, MMS collects only production data at the well level (where deep depth wells can be distinguished from shallow depth wells) while royalty-bearing versus royalty-free production is only identified at the lease level where production from all wells on the lease is commingled.
- The request to add text to § 203.69 to distinguish between RS leases and other leases issued after November 28, 2000, is not appropriate because there is a basis to distinguish between them. In particular, there is the possibility that leases may be issued after November 28, 2000, that do not have a royalty suspension, i.e., would not be RS leases.

D. Summary of the Deep Gas Royalty Relief Program in this Rule

The following five tables summarize the deep gas royalty relief incentives adopted in this rule. Each table refers to a different lease type. Abbreviations used in each table include:

BCF	Billion cubic feet.
K	Thousand.
MD	Measured depth (length in thousands of feet).
MMBtu	Million British thermal units.
NA	Not applicable.
PT	Price Threshold (2007$ per MMBtu).
RSS	Royalty Suspension Supplement (in BCF).
RSV	Royalty Suspension Volume (in BCF).

ST	Sidetrack.
TVD SS	True Vertical Depth Sub-Sea.

The last two columns of each of the following tables outline the royalty relief that exists in the current regulations and the additional relief adopted under section 344 rulemaking. The first range of numbers in each of these two columns represents the well depth (in feet), the second number represents the associated RSV or RSS granted (in BCF), and the third number represents the applicable price threshold (in $2007/MMBtu).

TABLE 1—TERMS APPLICABLE TO A LEASE WITH NO PREVIOUS PRODUCTION FROM A DEEP OR ULTRA-DEEP WELL, LOCATED IN WATER 0–200 METERS DEEP,

[Issued before 2001 or after 2003 or that Converted to the Royalty Relief Terms in the Existing Rule]

	Well type	Spud date	1st date produced	Depth (feet): RSV [RSS], PT	
				Royalty relief under existing regulations	Additional relief under adopted section 344 rulemaking
A	Well #1: Original well or ST.	Before 3/26/2003	Not Relevant	• None	• NA.
B	Well #1: Original well.	On or after 3/26/2003 and before 5/18/2007.	Before 5/3/2009 ..	• If 15K–18K TVD SS: 15 BCF, $10.15, or. • If ≥ 18K TVD SS: 25 BCF, $10.15.	• NA. • NA.
C	Well #1: ST	....	....	• If ≥ 15K TVD SS: 4 BCF+ (0.6 * MD) BCF up to 15 or 25 BCF, $10.15.	• NA.
D	Well #1: Original well.	On or after 5/18/2007.	....	• If 15K–18K TVD SS: 15 BCF, $10.15 [a], or. • If 18K–20K TVD SS: 25 BCF, $10.15 [a], or • If ≥ 20K TVD SS: 1st 25 BCF, $10.15 [a].	• NA. • NA. • If ≥ 20K TVD SS: Add 10 BCF, $4.55 [a].
E	Well #1: ST with MD ≥ 20K ft.	....	....	• If ≥ 20K TVD SS: 1st 25 BCF, $10.15 [a].	• If ≥ 20K TVD SS: Add 10 BCF, $4.55 [a].
F	Well #1: ST with MD < 20K ft.	....	....	• If ≥ 15K TVD SS: 4 BCF + (0.6 * MD) BCF up to 15 or 25 BCF, $10.15 [a].	• None.
G	Well #1: Original well or ST with MD ≥ 20K ft.	....	On or after 5/3/2009.	• None	• If ≥ 20K TVD SS: 35 BCF, $4.55 [a].
H	Well #1: Original well.	On or after 3/26/2003 and before 5/3/2009.	Never	• If 15K–18K TVD SS: [None], or .. • If ≥ 18K TVD SS: [5 BCF], $10.15 [a].	• NA.
I	Well #1: ST with MD ≥ 10K ft.	....	....	• If 15K–18K TVD SS: [None], or .. • If ≥ 18K TVD SS: [0.8 BCF + (0.12 * MD) BCF up to 5 BCF], $10.15 [a].	• NA.

[a] For wells on leases issued after December 18, 2008, the price threshold will be $4.55/MMBtu (adjusted for inflation after 2007) unless the lease terms prescribe a different price threshold.

For example, suppose an original well (one that does not use an existing wellbore) was drilled to a depth of 23,000 feet TVD SS between September and December 2007 (after the proposed rule was issued), on a lease that has had no production from a well completed at a depth deeper than 15,000 ft TVD SS. If the well starts producing in 2008, Table 1, row D indicates the well earns an RSV of 35 BCF. Further, the first 25 BCF of that RSV is subject to a price threshold of $10.15 per MMBtu (adjusted for inflation after 2007), while the remaining RSV of 10 BCF is subject to a price threshold of $4.55 per MMBtu (adjusted for inflation after 2007). Alternatively, if delays prevent production from starting until July of 2009, Table 1, row G indicates this well still earns an RSV of 35 BCF, but the entire RSV is subject to a price threshold of $4.55 per MMBtu (adjusted for inflation after 2007). If this well were unsuccessful rather than productive, Table 1, row H indicates that it earns an RSS of 5 BCF that is subject to a price threshold of $10.15 per MMBtu (adjusted for inflation after 2007).

TABLE 2—TERMS APPLICABLE TO A LEASE

[With Previous Production from a Deep Well completed between 15,000 and 18,000 feet TVD SS, Located in Water 0–200 Meters Deep, Issued before 2001 or after 2003 or Converted to the Royalty Relief Terms in the Existing Rule]

	Well type	Spud date	1st date produced	Depth (feet): RSV [RSS], PT	
				Royalty relief under existing regulations	Additional relief under adopted section 344 rulemaking
A	Well #2: Original well.	On or after 3/26/2003 and before 5/18/2007.	Before 5/3/2009 ..	• If 15K–18K TVD SS: None, or • If ≥ 18K TVD SS: 10 BCF, $10.15.	• NA.

TABLE 2—TERMS APPLICABLE TO A LEASE—Continued

[With Previous Production from a Deep Well completed between 15,000 and 18,000 feet TVD SS, Located in Water 0–200 Meters Deep, Issued before 2001 or after 2003 or Converted to the Royalty Relief Terms in the Existing Rule]

	Well type	Spud date	1st date produced	Depth (feet): RSV [RSS], PT	
				Royalty relief under existing regulations	Additional relief under adopted section 344 rulemaking
B	Well #2: ST			• If 15K–18K TVD SS: None, or • If ≥ 18K TVD SS: 4 BCF+ (0.6 * MD) BCF up to 10 BCF, $10.15.	• NA.
C	Well #2: Original well.	On or after 5/18/2007.		• If 15K–18K TVD SS: None, or • If 18K–20K TVD SS: 10 BCF, $10.15 [a].	• If ≥ 20K TVD SS: + 10 BCF if lease issued in lease sale held between 1/1/2004 and 12/31/2005 otherwise none, $10.15.
D	Well #2: ST with MD ≥ 20K ft.			• If 15K–18K TVD SS: None, or	• If ≥ 20K TVD SS: + 10 BCF if lease issued in lease sale held between 1/1/2004 and 12/31/2005 otherwise none, $10.15.
E	Well #2: ST with MD < 20K ft.			• If 18K–20K TVD SS: 4 BCF + (0.6 * MD) BCF up to 10 BCF, $10.15 [a].	• If ≥ 20K TVD SS: + 4BCF + (0.6 * MD) BCF if lease issued in lease sale held between 1/1/2004 and 12/31/2005 otherwise none, $10.15.
F	Well #2: Original well or ST.		On or after 5/3/2009.	• None	• None.
G	Well #2: Original well or ST with MD ≥ 10K ft.	On or after 3/26/2003 and before 5/3/2009.	Never	• If 15K–18K TVD SS: [None], or • If ≥ 18K TVD SS: [2 BCF], $10.15 [a].	• NA.

[a] For wells on leases issued after December 18, 2008, the price threshold will be $4.55/MMBtu (adjusted for inflation after 2007) unless the lease terms prescribe a different price threshold.

For example, suppose a sidetrack with a measured depth or length of 7,000 feet is drilled to a depth of 23,000 feet TVD SS beginning in September 2007 (after the proposed rule was issued), and begins production in December 2007 on a lease issued in 1998 that already has production from a well completed at 16,000 feet TVD SS. This well earns no additional RSV because Table 2, row E, last column shows that this 1998 lease is too old to come within the exception proposed for leases issued in lease sales held between January 1, 2004, and December 31, 2005. However, this ultra-deep short sidetrack is a qualified well entitled to share the remaining RSV, if any, earned by the deep well.

TABLE 3—TERMS APPLICABLE TO A LEASE WITH NO PREVIOUS PRODUCTION FROM A DEEP OR ULTRA-DEEP WELL, LOCATED IN WATER BETWEEN 200–400 METERS DEEP

	Well type	Spud date	1st date produced	Depth (feet): RSV [RSS], PT	
				Royalty relief under existing regulations	Additional relief under adopted section 344 rulemaking
A	Well #1: Original well or ST.	Before 5/18/2007	Not Relevant	• None	• None.
B	Well #1: Original well.	On or after 5/18/2007.	Before 5/3/2013		• If 15K–18K TVD SS: 15 BCF, $4.55 [a], or • If 18K–20K TVD SS: 25 BCF, $4.55 [a], or • If ≥ 20K TVD SS: 35 BCF, $4.55 [a].
C	Well #1: ST with MD ≥ 20K ft.				• If 15K–20K TVD SS: 4 BCF + (0.6 * MD) BCF up to 15 or 25 BCF, $4.55 [a], or • If ≥ 20K TVD SS: 35 BCF, $4.55 [a].
D	Well #1: ST with MD < 20K ft.				• If ≥ 15K TVD SS: 4 BCF+ (0.6 * MD) BCF up to 15 or 25 BCF, $4.55 [a].
E	Well #1: Original well.		On or after 5/3/2013.		• If 15K–20K TVD SS: None, or • If ≥ 20K TVD SS: 35 BCF, $4.55 [a].
F	Well #1: ST with MD ≥ 20K ft.				• If 15K–20K TVD SS: None, or • If ≥ 20K TVD SS: 35 BCF, $4.55 [a].
G	Well #1: ST with MD < 20K ft.				• None.

TABLE 3—TERMS APPLICABLE TO A LEASE WITH NO PREVIOUS PRODUCTION FROM A DEEP OR ULTRA-DEEP WELL, LOCATED IN WATER BETWEEN 200–400 METERS DEEP—Continued

	Well type	Spud date	1st date produced	Depth (feet): RSV [RSS], PT	
				Royalty relief under existing regulations	Additional relief under adopted section 344 rulemaking
H	Well #1: Original well.	On or after 5/18/2007 and before 5/3/2013.	Never		• If 15K–18K TVD SS: [None], or • If ≥ 18K TVD SS: [5 BCF], $4.55 [a].
I	Well #1: ST with MD ≥ 10K ft.				• If 15K–18K TVD SS: [None], or • If ≥ 18K TVD SS: [0.8 BCF+ (0.12 * MD) BCF up to 5 BCF], $4.55 [a].

[a] Unless the lease terms of a lease issued after December 18, 2008, prescribe a different price threshold.

For example, suppose a sidetrack with a measured depth or length of 9,000 feet is drilled to a depth of 18,000 feet TVD SS between February and October 2010 (after the proposed rule was issued) on a lease that has had no production from a well completed deeper than 15,000 ft TVD SS. If it starts producing in 2011, Table 3, row D indicates the well earns an RSV of 9.4 BCF subject to a price threshold of $4.55 per MMBtu (adjusted for inflation after 2007). Alternatively, if delays prevent production starting until July of 2013, Table 3, row G indicates this well earns no RSV. If this well were unsuccessful, Table 3, row I indicates that it would not qualify for an RSS because its measured depth is too short.

TABLE 4—TERMS APPLICABLE TO A LEASE WITH PREVIOUS PRODUCTION FROM A DEEP WELL COMPLETED BETWEEN 15,000 AND 18,000 FEET TVD SS, LOCATED IN WATER BETWEEN 200–400 METERS DEEP

	Well type	Spud date	1st date produced	Depth (feet): RSV [RSS], PT	
				Royalty relief under existing regulations	Additional relief under adopted section 344 rulemaking
A	Well #2: Original well.	On or after 5/18/2007 and before 5/3/2013.	Before 5/3/2013	• None	• If 15K–18K TVD SS: None, or • If 18K–20K TVD SS: 10 BCF, $4.55 [a], or • If ≥ 20K TVD SS: None.
B	Well #2: ST				• If 15K–18K TVD SS: None, or • If 18K–20K TVD SS: 4 BCF + (0.6 * MD) BCF up to 10 BCF, $4.55 [a], or • If ≥ 20K TVD SS: None.
C	Well #2: Original well or ST.	On or after 5/18/2007.	On or after 5/3/2013.		• None.
D	Well #2: Original well or ST with MD ≥ 10K ft.	On or after 5/18/2007 and before 5/3/2013.	Never		• If 15K–18K TVD SS: [None], or • If ≥ 18K TVD SS: [2 BCF], $4.55 [a].

[a] Unless the lease terms of a lease issued after December 18, 2008, prescribe a different price threshold.

For example, suppose an original well is drilled to a depth of 19,000 feet TVD SS between June and November 2011 (after the proposed rule was issued) on a lease that already has production from a well completed at 16,000 ft TVD SS. If it starts producing in March 2012, Table 4, row A indicates the well earns an RSV of 10 BCF for the lease. If the prior deep well also earned an RSV, then this 10 BCF is an additional RSV. However, if production is delayed until July 2013, Table 4, row C indicates this deep well earns no additional RSV; nor may any remaining RSV that the prior deep well may have earned be applied to production from this well.

TABLE 5—TERMS APPLICABLE TO A LEASE LOCATED IN WATER 0–200 METERS DEEP, ISSUED FROM 2001 THROUGH 2003 THAT DID NOT CONVERT FROM THE ROYALTY RELIEF TERMS WITH WHICH IT WAS ISSUED

	Well type	Spud date	1st date produced	Depth (feet): RSV [RSS], PT	
				Existing royalty relief in original lease terms	Additional relief under adopted section 344 rulemaking
A	Well #1: Original well or ST.	Before 5/18/ 2007	Within 5 years of lease effective date.	• If ≥ 15K in new reservoir: 20BCF, $4.08 (Sale 178), or. • If ≥ 15K in new reservoir: 20BCF, $5.83 (Sales 180, 182, 184, 185, or 187).	• None.

TABLE 5—TERMS APPLICABLE TO A LEASE LOCATED IN WATER 0–200 METERS DEEP, ISSUED FROM 2001 THROUGH 2003 THAT DID NOT CONVERT FROM THE ROYALTY RELIEF TERMS WITH WHICH IT WAS ISSUED—Continued

	Well type	Spud date	1st date produced	Depth (feet): RSV [RSS], PT	
				Existing royalty relief in original lease terms	Additional relief under adopted section 344 rulemaking
B		On after 5/18/2007.		• If 15K–20K in new reservoir: 20BCF, $4.08 (Sale 178), or • If 15K–20K in new reservoir: 20BCF, $5.83 (Sales 180, 182, 184, 185, or 187), or • If ≥ 20K in new reservoir: 1st 20 BCF, $4.08 (Sale 178) or $5.83 (Sales 180, 182, 184, 185, or 187).	• If 15K–20K TVD SS: None, or • If ≥ 20K TVD SS: Add 15 BCF, $4.55.
C			More than 5 years after lease effective date.	• None	• If 15K–20K TVD SS: None, or • If ≥ 20K in new reservoir: 35BCF, $4.55.

For example, suppose an original well or sidetrack is drilled to a depth of 23,000 feet TVD SS between August 2007 and March 2008 (after the proposed rule was issued) on a lease issued in November 2002. If this well starts producing from a reservoir that has not produced on any current lease, Table 5, row B indicates the well earns an RSV of 35 BCF. Further, the first 20 BCF of that RSV is subject to a price threshold of $5.83 per MMBtu (adjusted for inflation after 2007) while the remaining RSV of 15 BCF is subject to a price threshold of $4.55 per MMBtu (adjusted for inflation after 2007).

Additional information on the structure of the deep gas royalty relief incentives both in existing regulations and in this rule can be found on the MMS Web site at: *http://www.mms.gov/econ/*.

Procedural Matters

Regulatory Planning and Review (Executive Order (E.O.) 12866)

This final rule is a significant rule as determined by the Office of Management and Budget (OMB) and is subject to review under E.O. 12866. We have made the assessments required by E.O. 12866 and the results are:

(1) This final rule will not have an economic effect of $100 million or more in any year.

The added eligibility of leases in water depths from 200 to 400 meters for the deep gas royalty incentive will represent a 12 percent increase in the estimated gas resources that will be eligible for the deep gas incentive, and only a fraction of those resources will actually qualify because the program would sunset in May 2013. Further, existing relief terms already grant leases located partly or entirely in less than 200 meters of water with ultra-deep wells over 70 percent of the relief this rule prescribes (25 BCF increasing to 35 BCF for successful ultra-deep wells). However, because this incentive will have no explicit sunset date, it conceivably could apply to all undiscovered ultra-deep resources.

One of the few areas of significant programmatic discretion MMS has in implementing section 344 is in the choice of the price threshold for RSVs. This rule sets a different and lower price threshold for RSVs earned and used by ultra-deep wells, except to the extent of the royalty relief that an ultra-deep well would earn under the existing rule on leases in existence on the effective date of this final rule. This different price threshold is low enough to cancel relief whose value might otherwise have been over $100 million at current and projected gas prices.

The MMS has updated key parts of the economic analysis done for the original deep gas rule to reflect both higher gas prices and the larger open-ended duration of RSVs for ultra-deep wells. The update estimates the incremental production and net fiscal cost which would result from the added incentives on ultra-deep wells and additional deep wells for a range of price thresholds applied to the anticipated gas market environment. The price threshold adopted in this rule for ultra-deep gas royalty relief is the same as the price threshold used for deepwater royalty relief for leases issued before 2001, after adjusting for inflation ($4.55 per MMBtu in 2007 dollars, to be further adjusted for inflation after 2007). For comparison, MMS estimates that the ultra-deep well and additional deep well incentives required by the Energy Policy Act, together with a reduced price threshold of $4.55 per MMBtu (adjusted for inflation after 2007) would, over the next 15 years, increase deep gas production by 54 BCF instead of by 223 BCF, and reduce the aggregate loss in Federal royalty receipts by $955 million (present value $508 million, or about $34 million in an average year) relative to using the same price threshold as in the existing regulations. Over the next 15 years, we estimate that the adopted price threshold of $4.55 per MMBtu would keep the present value of the aggregate fiscal cost of this rulemaking below $100 million resulting in an average annual fiscal cost of about $7 million, generate a social welfare measure of consumer plus producer surplus of only about $4,200 in present value, and add over 50 billion cubic feet of deep gas production to the domestic energy supply. The full economic analysis for the original deep gas rule, as well as this update, is available at: *http://www.mms.gov/econ*.

As of the beginning of fiscal year 2008, this rule also adds 750 currently active Alaska leases to the roughly 2,700 deepwater leases in the GOM, as well as future leases in both areas, that could apply for an RSV (for both oil and gas) before production or to expand production. Again, section 346 of the Energy Policy Act mandates this expansion of existing authority to consider and possibly grant discretionary royalty relief. So, the provisions in this rule simply provide a framework for a process—by themselves they have no direct economic effect over and above that which may result from the statutory language in section 346.

Historically, we have received less than one application per year in the GOM under the procedure now being extended to leases offshore of Alaska. Those leases that previously have qualified for this form of relief have avoided an average of $30 million annually in royalties since 1999, an amount that would have been much larger but for price thresholds. Accordingly, the value of the relief that may be granted indirectly by this added rulemaking action may not significantly ease the daunting obstacles to developing offshore Alaska. In any event, the award of royalty relief in this form to leases offshore of Alaska is discretionary, and MMS will only approve relief in the appropriate amount or provide an exception to the established price thresholds if MMS deemed the applicable project uneconomic absent relief. Thus, for these reasons, there will be no negative effect on Federal revenues from this rulemaking.

(2) This final rule will not create any inconsistencies or otherwise interfere with actions by other Federal 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, will not conflict with the work of other Federal agencies.

(3) This final rule will not alter the budgetary effects of entitlements, grants, user fees, or loan programs or the rights or obligations of their recipients.

(4) This final rule raises novel legal or policy issues because it implements a statutory requirement to expand a previously established, but so far disappointing royalty relief program for deep gas in the GOM. The rule also serves to eliminate any recurrence of an unintended policy issue by establishing default price thresholds for all future leases that may be issued with royalty relief incentives. The other part of the rule, which extends a long established but little used discretionary royalty relief authority to leases offshore Alaska, raises no unusual issues because, with the exception of explicit statutory requirements under the DWRRA, programmatically the price thresholds have always been treated as a complementary policy variable to the royalty suspension volumes for dealing with applications of discretionary royalty relief on a case-by-case basis.

Regulatory Flexibility Act

The Department of the Interior certifies that this final rule will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*).

The provisions of this final rule will not have a significant adverse economic effect on offshore lessees and operators, including those that are classified as small businesses.

This rule expands existing deep gas well production incentives. A detailed analysis of the small business impacts and alternatives for the deep gas provisions established in 2004 were considered and can be found in the economic analysis of the original version of this regulation available at: *http://www.mms.gov/econ*. This rule will not materially alter the findings of that analysis because it will expand by less than 5 percent the set of leases affected, based on the number of existing and potential leases in the interval from entirely deeper than 200 to entirely less than 400 meters of water relative to those in the interval from 0 to partly or entirely less than 200 meters of water that are already covered by the existing rule.

The rule also extends the potential for discretionary royalty relief to 263 OCS leases located offshore Alaska, some of which may qualify as marginally uneconomic. Five of the eight companies involved are ''majors'' and therefore are not small entities. In any single year, MMS is likely to receive only a small number of royalty relief applications, if indeed it receives any at all. That limits the number of entities this rule may affect. In the past, we have received less than one application a year from a candidate set of 2,700 leases in the GOM. Also, because firms initiate applications, they have the ability to avoid adverse effects they foresee. A Regulatory Flexibility Analysis is not required. A Small Entity Compliance Guide is not required.

Small Business Regulatory Enforcement Fairness Act

The final rule is not a major rule under 5 U.S.C. 804(2) the Small Business Regulatory Enforcement Fairness Act. This final rule:

a. Will expand coverage of existing royalty relief programs by 15 percent, adding about 800 leases to the set of about 5,000 leases eligible either for (1) the deep gas incentive or (2) to apply for royalty relief before production begins on the lease. These leases represent only a fraction of the leases already eligible for these incentives as a result of earlier rules. The effects of the provisions in this rule will not add substantially to those estimated for the earlier rules because relatively little relief is likely to be granted under the new provisions.

b. Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, local government agencies, or geographic regions. The additional deep gas incentive provisions will not cause an increase in prices and should result in some downward pressure on prices, but its degree and ultimate effect is difficult to anticipate.

c. Will not have significant adverse effects on competition, employment, investment, or the ability of U.S.-based enterprises to compete with foreign-based enterprises. Companies eligible for the new royalty relief should produce some more natural gas and earn more income while encountering no negative effects.

Unfunded Mandates Reform Act

This final rule will not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than $100 million per year. The final rule will not have a significant or unique effect on State, local, or tribal governments or the private sector. A statement containing the information required by the Unfunded Mandates Reform Act (2 U.S.C. 1531 *et seq.*) is not required.

Takings Implication Assessment (E.O. 12630)

Under the criteria in E.O. 12630, this final rule does not have significant takings implications. The final rule is not a governmental action capable of interference with constitutionally protected property rights. A Takings Implication Assessment is not required.

Federalism (E.O. 13132)

Under the criteria in E.O. 13132, this final rule will not have sufficient federalism implications to warrant the preparation of a Federalism Assessment. As noted above, the deep gas provisions in this rule should have a small effect relative to the proposed rule, which itself may have only a small consequence ($1–$2 million per year) on Gulf Coast states in the form of reduced payments under section 8(g) of the OCSLA. Any relief awarded to offshore Alaska leases will not affect that State's share of OCS revenue because the discretionary royalty relief rules extended by this rule to leases offshore of Alaska are designed to grant relief only when production and thus royalty payments would not otherwise occur.

Civil Justice Reform (E.O. 12988)

This rule complies with the requirements of E.O. 12988. Specifically, this rule:

(a) Meets the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation; and

(b) Meets the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

Consultation With Indian Tribes (E.O. 13175)

Under the criteria in E.O. 13175, we have evaluated this final rule and determined that it has no potential effects on federally recognized Indian tribes. There are no Indian or tribal lands in the OCS.

Paperwork Reduction Act

An information collection package was submitted to OMB for review and approval under section 3507(d) of the PRA. The OMB has approved the information collection requirements for this rulemaking and assigned OMB Control Number 1010–0173 (exp. 8/31/10; 3 burden hours). The title of the collection of information for this final rule is ''30 CFR 203, Royalty Relief—Ultra-Deep Gas Wells and Deep Gas Wells on Oil and Gas Leases; Extension of Royalty Relief Provisions to Leases Offshore of Alaska.'' Respondents are those from the approximately 130 Federal oil and gas lessees who may apply for royalty relief. Responses to this collection are required to obtain benefits. The frequency of response is on occasion. The information collection does not include questions of a sensitive nature. The MMS will protect proprietary information according to the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations (43 CFR 2), 30 CFR part 203, ''Does my application have to include all leases in the field?'' and 30 CFR 250.197, ''Data and information to be made available to the public or for limited inspection.''

We received eight comments due to this rulemaking. Only one commenter brought up information collection redundancy; however, MMS determined that there is no redundancy and that the requirements were new. Therefore, there were no changes in the information collection requirements from the proposed rule to the final rule. When the rule becomes effective, MMS will merge these hours into the primary collection for 30 CFR 203 (OMB Control Number 1010–0071, expiration 12/31/09).

An agency 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. The public may comment, at any time, on the accuracy of the information collection burden in this rule and may submit any comments to the Department of the Interior; Minerals Management Service; Attention: Regulations and Standards Branch; Mail Stop 4024; 381 Elden Street; Herndon, Virginia 20170–4817.

National Environmental Policy Act

We determined this rule is categorically excluded from requirements for analysis under the National Environmental Policy Act and the Department Manual at 516 DM. This rule deals with financial matters and has no direct effect on MMS decisions on oil and gas operations with the potential to affect the environment; hence, an Environmental Impact Statement is not required. Pursuant to Department Manual 516 DM 2.3A (2), section 1.10 of 516 DM 2, Appendix 1 excludes from documentation in an environmental assessment or impact statement ''policies, directives, regulations and guidelines of an administrative, financial, legal, technical or procedural nature; or the environmental effects of which are too broad, speculative or conjectural to lend themselves to meaningful analysis and will be subject later to the NEPA process, either collectively or case-by-case.'' Section 1.3 of the same appendix clarifies that royalties and audits are considered routine financial transactions that are subject to categorical exclusion from the NEPA process. None of the exceptional circumstances set forth in 516 DM 2 Appendix 2 apply.

Data Quality Act

In developing this rule, we did not conduct or use a study, experiment, or survey requiring peer review under the Data Quality Act (Pub. L. 106–554, app. C § 515, 114 Stat. 2763, 2763A–153–154).

Effects on the Energy Supply (E.O. 13211)

This rule is not a significant energy action under the definition in E.O. 13211. A Statement of Energy Effects is not required.

List of Subjects

30 CFR Part 203

Continental shelf, Government contracts, Mineral royalties, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements.

30 CFR Part 260

Continental shelf, Government contracts, Mineral royalties, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements.

Dated: June 19, 2008.

C. Stephen Allred,

Assistant Secretary—Land and Minerals Management.

■ For the reasons stated in the preamble, the Minerals Management Service (MMS) amends 30 CFR Part 203 as follows:

PART 203—RELIEF OR REDUCTION IN ROYALTY RATES

■ 1. The authority citation for part 203 is revised 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; 42 U.S.C. 15903–15906; 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 revising the definitions for ''certified unsuccessful well'', ''deep well'', ''development project'', ''expansion project'', ''original well'', ''royalty suspension supplement'' and ''royalty suspension volume''; removing the definition of ''qualified well''; and by adding definitions for ''non-converted lease'', ''phase 1 ultra-deep well'', ''phase 2 ultra-deep well'', ''phase 3 ultra-deep well'', ''qualified deep well'', ''qualified ultra-deep well'', ''qualified wells'', and ''ultra-deep well'' to read as follows:

§ 203.0 What definitions apply to this part?

* * * * *

Certified unsuccessful well means an original well or a sidetrack with a sidetrack measured depth (i.e., length) of at least 10,000 feet, on your lease that:

(1) You begin drilling on or after March 26, 2003, and before May 3, 2009, on a lease that is located in water partly or entirely less than 200 meters deep and that is not a non-converted lease, or on or after May 18, 2007, and before May 3, 2013, on a lease that is located in water entirely more than 200 meters and entirely less than 400 meters deep;

(2) You begin drilling before your lease produces gas or oil from a well with a perforated interval the top of which is at least 18,000 feet true vertical depth subsea (TVD SS), (i.e., below the datum at mean sea level);

(3) You drill to at least 18,000 feet TVD SS with a target reservoir on your lease, identified from seismic and related data, deeper than that depth;

(4) Fails to meet the producibility requirements of 30 CFR part 250, subpart A, and does not produce gas or oil, or meets those producibility requirements and MMS agrees it is not commercially producible; and

(5) For which you have provided the notices and information required under § 203.47.

* * * * *

Deep well means either an original well or a sidetrack with a perforated interval the top of which is at least 15,000 feet TVD SS and less than 20,000 feet TVD SS. A deep well subsequently re-perforated at less than 15,000 feet TVD SS in the same reservoir is still a deep well.

* * * * *

Development project means a project to develop one or more oil or gas reservoirs located on one or more contiguous leases that have had no production (other than test production) before the current application for royalty relief and are either:

(1) Located in a planning area offshore Alaska; or

(2) Located in the GOM in a water depth of at least 200 meters and wholly west of 87 degrees, 30 minutes West longitude, and were issued in a sale held after November 28, 2000.

* * * * *

Expansion project means a project that meets the following requirements:

(1) You must propose the project in a Development and Production Plan, a Development Operations Coordination Document (DOCD), or a Supplement to a DOCD, approved by the Secretary of the Interior after November 28, 1995.

(2) The project must be located on either:

(i) A pre-Act lease in the GOM, or a lease in the GOM issued in a sale held after November 28, 2000, located wholly west of 87 degrees, 30 minutes West longitude; or

(ii) A lease in a planning area offshore Alaska.

(3) On a pre-Act lease in the GOM, the project:

(i) Must significantly increase the ultimate recovery of resources from one or more reservoirs that have not previously produced (extending recovery from reservoirs already in production does not constitute a significant increase); and

(ii) Must involve a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well project, etc.).

(4) For a lease issued in a planning area offshore Alaska, or in the GOM after November 28, 2000, the project must involve a new well drilled into a reservoir that has not previously produced.

(5) On a lease in the GOM, the project must not include a reservoir the production from which an RSV under §§ 203.30 through 203.36 or §§ 203.40 through 203.48 would be applied.

* * * * *

Non-converted lease means a lease located partly or entirely in water less than 200 meters deep issued in a lease sale held after January 1, 2001, and before January 1, 2004, whose original lease terms provided for an RSV for deep gas production and the lessee has not exercised the option under § 203.49 to replace the lease terms for royalty relief with those in § 203.0 and §§ 203.40 through 203.48.

Original Well means a well that is drilled without utilizing an existing wellbore. An original well includes all sidetracks drilled from the original wellbore either before the drilling rig moves off the well location or after a temporary rig move that MMS agrees was forced by a weather or safety threat and drilling resumes within 1 year. A bypass from an original well (e.g., drilling around material blocking the hole or to straighten crooked holes) is part of the original well.

* * * * *

Phase 1 ultra-deep well means an ultra-deep well on a lease that is located in water partly or entirely less than 200 meters deep for which drilling began before May 18, 2007, and that begins production before May 3, 2009, or that meets the requirements to be a certified unsuccessful well.

Phase 2 ultra-deep well means an ultra-deep well for which drilling began on or after May 18, 2007; and that either meets the requirements to be a certified unsuccessful well or that begins production:

(1) Before the date which is 5 years after the lease issuance date on a non-converted lease; or

(2) Before May 3, 2009, on all other leases located in water partly or entirely less than 200 meters deep; or

(3) Before May 3, 2013, on a lease that is located in water entirely more than 200 meters and entirely less than 400 meters deep.

Phase 3 ultra-deep well means an ultra-deep well for which drilling began on or after May 18, 2007, and that begins production:

(1) On or after the date which is 5 years after the lease issuance date on a non-converted lease; or

(2) On or after May 3, 2009, on all other leases located in water partly or entirely less than 200 meters deep; or

(3) On or after May 3, 2013, on a lease that is located in water entirely more than 200 meters and entirely less than 400 meters deep.

* * * * *

Qualified deep well means:

(1) On a lease that is located in water partly or entirely less than 200 meters deep that is not a non-converted lease, a deep well for which drilling began on or after March 26, 2003, that produces natural gas (other than test production), including gas associated with oil production, before May 3, 2009, and for which you have met the requirements prescribed in § 203.44;

(2) On a non-converted lease, a deep well that produces natural gas (other than test production) before the date which is 5 years after the lease issuance date from a reservoir that has not produced from a deep well on any lease; or

(3) On a lease that is located in water entirely more than 200 meters but entirely less than 400 meters deep, a deep well for which drilling began on or after May 18, 2007, that produces natural gas (other than test production), including gas associated with oil production before May 3, 2013, and for which you have met the requirements prescribed in § 203.44.

Qualified ultra-deep well means:

(1) On a lease that is located in water partly or entirely less than 200 meters deep that is not a non-converted lease, an ultra-deep well for which drilling began on or after March 26, 2003, that produces natural gas (other than test production), including gas associated with oil production, and for which you have met the requirements prescribed in § 203.35 or § 203.44, as applicable; or

(2) On a lease that is located in water entirely more than 200 meters and entirely less than 400 meters deep, or on a non-converted lease, an ultra-deep well for which drilling began on or after May 18, 2007, that produces natural gas (other than test production), including gas associated with oil production, and for which you have met the requirements prescribed in § 203.35.

Qualified well means either a qualified deep well or a qualified ultra-deep well.

* * * * *

Royalty suspension supplement (RSS) means a royalty suspension volume resulting from drilling a certified unsuccessful well that is applied to future natural gas and oil production generated at any drilling depth on, or allocated under an MMS-approved unit agreement to, the same lease.

Royalty suspension volume (RSV) means a volume of production from a lease that is not subject to royalty under the provisions of this part.

* * * * *

Ultra-deep well means either an original well or a sidetrack completed with a perforated interval the top of which is at least 20,000 feet TVD SS. An ultra-deep well subsequently re-perforated less than 20,000 feet TVD SS in the same reservoir is still an ultra-deep well.

Ultra-deep short sidetrack means an ultra-deep well that is a sidetrack with a sidetrack measured depth (i.e., length) of less than 20,000 feet.

* * * * *

■ 3. In § 203.1, the introductory text and paragraph (b) are revised, and new paragraph (d) is added to read as follows:

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

The Outer Continental Shelf (OCS) Lands Act, 43 U.S.C. 1337, as amended by the OCS Deep Water Royalty Relief Act (DWRRA), Public Law 104–58 and the Energy Policy Act of 2005, Public Law 109–058 authorizes us to grant royalty relief in four situations.

* * * * *

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

* * * * *

(d) Under 42 U.S.C. 15904–15905, we may suspend royalties for designated volumes of gas production from deep and ultra-deep wells on a lease if:

(1) Your lease is in shallow water (water less than 400 meters deep) and you produce from an ultra-deep well (top of the perforated interval is at least 20,000 feet TVD SS) or your lease is in waters entirely more than 200 meters and entirely less than 400 meters deep and you produce from a deep well (top of the perforated interval is at least 15,000 feet TVD SS);

(2) Your lease is in the designated area of the GOM (wholly west of 87 degrees, 30 minutes west longitude); and

(3) Your lease is not eligible for deep water royalty relief.

■ 4. In § 203.2, the section heading and paragraphs (b), (d), and (e) are revised, and new paragraphs (f), (g), and (h) are added to read as follows:

§ 203.2 How can I obtain royalty relief?

* * * * *

If you have a lease . . .	And if you . . .	Then we may grant you . . .
* *	* * *	* *
(b) Located in a designated GOM deep water area (i.e., 200 meters or greater) and acquired in a lease sale held before November 28, 1995, or after November 28, 2000.	Propose an expansion project and can demonstrate your project is uneconomic without royalty relief.	A royalty suspension for a minimum production volume plus any additional production large enough to make the project economic (see §§ 203.60 through 203.79).
* *	* * *	* *
(d) Located in a designated GOM deep water area and acquired in a lease sale held after November 28, 2000.	Propose a development project and can demonstrate that the suspension volume, if any, for your lease is not enough to make development economic.	A royalty suspension for a minimum production volume plus any additional volume needed to make your project economic (see §§ 203.60 through 203.79).
(e) Where royalty relief would recover significant additional resources or, offshore Alaska or in certain areas of the GOM, would enable development.	Are not eligible to apply for end-of-life or deep water royalty relief, but show us you meet certain eligibility conditions.	A royalty modification in size, duration, or form that makes your lease or project economic (see § 203.80).
(f) Located in a designated GOM shallow water area and acquired in a lease sale held before January 1, 2001, or after January 1, 2004, or have exercised an option to substitute for royalty relief in your lease terms.	Drill a deep well on a lease that is not eligible for deep water royalty relief and you have not previously produced oil or gas from a deep well or an ultra-deep well.	A royalty suspension for a volume of gas produced from successful deep and ultra-deep wells, or, for certain unsuccessful deep and ultra-deep wells, a smaller royalty suspension for a volume of gas or oil produced by all wells on your lease (see §§ 203.40 through 203.49).
(g) Located in a designated GOM shallow water area.	Drill and produce gas from an ultra-deep well on a lease that is not eligible for deep water royalty relief and you have not previously produced oil or gas from an ultra-deep well.	A royalty suspension for a volume of gas produced from successful ultra-deep and deep wells on your lease (see §§ 203.30 through 203.36).
(h) Located in planning areas offshore Alaska	Propose an expansion project or propose a development project and can demonstrate that the project is uneconomic without relief or that the suspension volume, if any, for your lease is not enough to make development economic.	A royalty suspension for a minimum production volume plus any additional volume needed to make your project economic (see §§ 203.60, 203.62, 203.67 through 203.70, §§ 203.73 and 203.76 through 203.79).

■ 5. A new undesignated center heading and new §§ 203.30 through 203.36 are added to subpart B to read as follows:

Royalty Relief for Drilling Ultra–Deep Wells on Leases Not Subject to Deep Water Royalty Relief

Royalty Relief for Drilling Ultra–Deep Wells on Leases Not Subject to Deep Water Royalty Relief

§ 203.30 Which leases are eligible for royalty relief as a result of drilling a phase 2 or phase 3 ultra-deep well?

Your lease may receive a royalty suspension volume (RSV) under §§ 203.31 through 203.36 if the lease meets all the requirements of this section.

(a) The lease is located in the GOM wholly west of 87 degrees, 30 minutes West longitude in water depths entirely less than 400 meters deep.

(b) The lease has not produced gas or oil from a deep well or an ultra-deep well, except as provided in § 203.31(b).

(c) If the lease is located entirely in more than 200 meters and entirely less than 400 meters of water, it must either:

(1) Have been issued before November 28, 1995, and not been granted deep water royalty relief under 43 U.S.C. 1337(a)(3)(C), added by section 302 of the Deep Water Royalty Relief Act; or

(2) Have been issued after November 28, 2000, and not been granted deep water royalty relief under §§ 203.60 through 203.79.

§ 203.31 If I have a qualified phase 2 or qualified phase 3 ultra-deep well, what royalty relief would that well earn for my lease?

(a) Subject to the administrative requirements of § 203.35 and the price conditions in § 203.36, your qualified well earns your lease an RSV shown in the following table in billions of cubic feet (BCF) or in thousands of cubic feet (MCF) as prescribed in § 203.33:

If you have a qualified phase 2 or qualified phase 3 ultra-deep well that is:	Then your lease earns an RSV on this volume of gas production:
(1) An original well,	35 BCF.
(2) A sidetrack with a sidetrack measured depth of at least 20,000 feet,	35 BCF.
(3) An ultra-deep short sidetrack that is a phase 2 ultra-deep well,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 25 BCF.
(4) An ultra-deep short sidetrack that is a phase 3 ultra-deep well,	0 BCF.

(b)(1) This paragraph applies if your lease:

(i) Has produced gas or oil from a deep well with a perforated interval the top of which is less than 18,000 feet TVD SS;

(ii) Was issued in a lease sale held between January 1, 2004, and December 31, 2005; and

(iii) The terms of your lease expressly incorporate the provisions of §§ 203.41 through 203.47 as they existed at the time the lease was issued.

(2) Subject to the administrative requirements of § 203.35 and the price conditions in § 203.36, your qualified well earns your lease an RSV shown in the following table in BCF or MCF as prescribed in § 203.33:

If you have a qualified phase 2 ultra-deep well that is . . .	Then your lease earns an RSV on this volume of gas production:
(i) An original well or a sidetrack with a sidetrack measured depth of at least 20,000 feet TVD SS,	10 BCF.
(ii) An ultra-deep short sidetrack,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 10 BCF.

(c) Lessees may request a refund of or recoup royalties paid on production from qualified phase 2 or phase 3 ultra-deep wells that:

(1) Occurs before December 18, 2008 and

(2) Is subject to application of an RSV under either § 203.31 or § 203.41.

(d) The following examples illustrate how this section applies. These examples assume that your lease is located in the GOM west of 87 degrees, 30 minutes West longitude and in water less than 400 meters deep (see § 203.30(a)), has no existing deep or ultra-deep wells and that the price thresholds prescribed in § 203.36 have not been exceeded.

Example 1: In 2008, you drill and begin producing from an ultra-deep well with a perforated interval the top of which is 25,000 feet TVD SS, and your lease has had no prior production from a deep or ultra-deep well. Assuming your lease has no deepwater royalty relief (see § 203.30(c)), your lease is eligible (according to § 203.30(b)) to earn an RSV under § 203.31 because it has not yet produced from a deep well. Your lease earns an RSV of 35 BCF under this section when this well begins producing. According to § 203.31(a), your 25,000 foot well qualifies your lease for this RSV because the well was drilled after the relief authorized here became effective (when the proposed version of this rule was published on May 18, 2007) and produced from an interval that meets the criteria for an ultra-deep well (i.e., is a phase 2 ultra-deep well as defined in § 203.0). Then in 2014, you drill and produce from another ultra-deep well with a perforated interval the top of which is 29,000 feet TVD SS. Your lease earns no additional RSV under this section when this second ultra-deep well produces, because your lease no longer meets the condition in § 203.30(b)) of no production from a deep well. However, any remaining RSV earned by the first ultra-deep well on your lease would be applied to production from both the first and the second ultra-deep wells as prescribed in § 203.33(a)(2), or § 203.33(b)(2) if your lease is part of a unit.

Example 2: In 2005, you spudded and began producing from an ultra-deep well with a perforated interval the top of which is 23,000 feet TVD SS. Your lease earns no RSV under this section from this phase 1 ultra-deep well (as defined in § 203.0) because you spudded the well before the publication date (May 18, 2007) of the proposed rule when royalty relief under § 203.31(a) became effective. However, this ultra-deep well may earn an RSV of 25 BCF for your lease under § 203.41 (that became effective May 3, 2004), if the lease is located in water depths partly or entirely less than 200 meters and has not previously produced from a deep well (§ 203.30(b)).

Example 3: In 2000, you began producing from a deep well with a perforated interval the top of which is 16,000 feet TVD SS and your lease is located in water 100 meters deep. Then in 2008, you drill and produce from a new ultra-deep well with a perforated interval the top of which is 24,000 feet TVD SS. Your lease earns no RSV under either this section or § 203.41 because the 16,000-foot well was drilled before we offered any way to earn an RSV for producing from a deep well (see dates in the definition of qualified well in § 203.0) and because the existence of the 16,000-foot well means the lease is not eligible (see § 203.30(b)) to earn an RSV for the 24,000-foot well. Because the lease existed in the year 2000, it cannot be eligible for the exception to this eligibility condition provided in § 203.31(b).

Example 4: In 2008, you spud and produce from an ultra-deep well with a perforated interval the top of which is 22,000 feet TVD SS, your lease is located in water 300 meters deep, and your lease has had no previous production from a deep or ultra-deep well. Your lease earns an RSV of 35 BCF under this section when this well begins producing because your lease meets the conditions in § 203.30 and the well fits the definition of a phase 2 ultra-deep well (in § 203.0). Then in 2010, you spud and produce from a deep well with a perforated interval the top of which is 16,000 feet TVD SS. Your 16,000-foot well earns no RSV because it is on a lease that already has a producing well at least 18,000 feet subsea (see § 203.42(a)), but any remaining RSV earned by the ultra-deep well would also be applied to production from the deep well as prescribed in § 203.33(a)(2), or § 203.33(b)(2) if your lease is part of a unit and § 203.43(a)(2), or § 203.43(b)(2) if your lease is part of a unit. However, if the 16,000-foot deep well does not begin production until 2016 (or if your lease were located in water less than 200 meters deep), then the 16,000-foot well would not be a qualified deep well because this well does not begin production within the interval specified in the definition of a qualified well in § 203.0, and the RSV earned by the ultra-deep well would not be applied to production from this (unqualified) deep well.

Example 5: In 2008, you spud a deep well with a perforated interval the top of which is 17,000 feet TVD SS that becomes a qualified well and earns an RSV of 15 BCF under § 203.41 when it begins producing. Then in 2011, you spud an ultra-deep well with a perforated interval the top of which is 26,000 feet TVD SS. Your 26,000-foot well becomes a qualified ultra-deep well because it meets the date and depth conditions in this definition under § 203.0 when it begins producing, but your lease earns no additional RSV under this section or § 203.41 because it is on a lease that already has production from a deep well (see § 203.30(b)). Both the qualified deep well and the qualified ultra-deep well would share your lease's total RSV of 15 BCF in the manner prescribed in §§ 203.33 and 203.43.

Example 6: In 2008, you spud a qualified ultra-deep well that is a sidetrack with a sidetrack measured depth of 21,000 feet and a perforated interval the top of which is 25,000 feet TVD SS. This well meets the definition of an ultra-deep well but is too long to be classified an ultra-deep short sidetrack in § 203.0. If your lease is located in 150 meters of water and has not previously produced from a deep well, your lease earns an RSV of 35 BCF because it was drilled after the effective date for earning this RSV. Further, this RSV applies to gas production from this and any future qualified deep and qualified ultra-deep wells on your lease, as prescribed in § 203.33. The absence of an expiration date for earning an RSV on an ultra-deep well means this long sidetrack well becomes a qualified well whenever it starts production. If your sidetrack has a sidetrack measured depth of 14,000 feet and begins production in March 2009, it earns an RSV of 12.4 BCF under this section because it meets the definitions of a phase 2 ultra-deep well (production begins before the expiration date for the pre-existing relief in its water depth category) and an ultra-deep short sidetrack in § 203.0. However, if it does not begin production until 2010, it earns no RSV because it is too short as a phase 3 ultra-deep well to be a qualified ultra-deep well.

Example 7: Your lease was issued in June 2004 and expressly incorporates the provisions of §§ 203.41 through 203.47 as they existed at that time. In January 2005, you spud a deep well (well no. 1) with a perforated interval the top of which is 16,800 feet TVD SS that becomes a qualified well and earns an RSV of 15 BCF under § 203.41 when it begins producing. Then in February 2008, you spud an ultra-deep well (well no. 2) with a perforated interval the top of which is 22,300 feet that begins producing in November 2008, after well no. 1 has started production. Well no. 2 earns your lease an additional RSV of 10 BCF under paragraph (b) of this section because it begins production in time to be classified as a phase 2 ultra-deep well. If, on the other hand, well no. 2 had begun producing in June 2009, it would earn no additional RSV for the lease because it would be classified as a phase 3 ultra-deep well and thus is not entitled to the exception under paragraph (b) of this section.

§ 203.32 What other requirements or restrictions apply to royalty relief for a qualified phase 2 or phase 3 ultra-deep well?

(a) If a qualified ultra-deep well on your lease is within a unitized portion of your lease, the RSV earned by that well under this section applies only to your lease and not to other leases within the unit or to the unit as a whole.

(b) If your qualified ultra-deep well is a directional well (either an original well or a sidetrack) drilled across a lease line, then either:

(1) The lease with the perforated interval that initially produces earns the RSV or

(2) If the perforated interval crosses a lease line, the lease where the surface of the well is located earns the RSV.

(c) Any RSV earned under § 203.31 is in addition to any royalty suspension supplement (RSS) for your lease under § 203.45 that results from a different wellbore.

(d) If your lease earns an RSV under § 203.31 and later produces from a deep well that is not a qualified well, the RSV is not forfeited or terminated, but you may not apply the RSV earned under § 203.31 to production from the non-qualified well.

(e) You owe minimum royalties or rentals in accordance with your lease terms notwithstanding any RSVs allowed under paragraphs (a) and (b) of § 203.31.

(f) Unused RSVs transfer to a successor lessee and expire with the lease.

§ 203.33 To which production do I apply the RSV earned by qualified phase 2 and phase 3 ultra-deep wells on my lease or in my unit?

(a) You must apply the RSV allowed in § 203.31(a) and (b) to gas volumes produced from qualified wells on or after May 18, 2007, reported on the Oil and Gas Operations Report, Part A (OGOR–A) for your lease under § 216.53. All gas production from qualified wells reported on the OGOR–A, including production not subject to royalty, counts toward the total lease RSV earned by both deep or ultra-deep wells on the lease.

(b) This paragraph applies to any lease with a qualified phase 2 or phase 3 ultra-deep well that is not within an MMS-approved unit. Subject to the price conditions of § 203.36, you must apply the RSV prescribed in § 203.31 as required under the following paragraphs (b)(1) and (b)(2) of this section.

(1) You must apply the RSV to the earliest gas production occurring on and after the later of May 18, 2007, or the date the first qualified phase 2 or phase 3 ultra-deep well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production from qualified wells on your lease, regardless of their depth, for which you have met the requirements in § 203.35 or § 203.44.

(c) This paragraph applies to any lease with a qualified phase 2 or phase 3 ultra-deep well where all or part of the lease is within an MMS-approved unit. Under the unit agreement, a share of the production from all the qualified wells in the unit participating area would be allocated to your lease each month according to the participating area percentages. Subject to the price conditions of § 203.36, you must apply the RSV prescribed in § 203.31 as follows:

(1) You must apply the RSV to the earliest gas production occurring on and after the later of May 18, 2007, or the date that the first qualified phase 2 or phase 3 ultra-deep well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production:

(i) From qualified wells on the non-unitized area of your lease, regardless of their depth, for which you have met the requirements in § 203.35 or § 203.44; and

(ii) Allocated to your lease under an MMS-approved unit agreement from qualified wells on unitized areas of your lease and on other leases in participating areas of the unit, regardless of their depth, for which the requirements in § 203.35 or § 203.44 have been met. The allocated share under paragraph (a)(2)(ii) of this section does not increase the RSV for your lease.

Example: The east half of your lease A is unitized with all of lease B. There is one qualified phase 2 ultra-deep well on the non-unitized portion of lease A that earns lease A an RSV of 35 BCF under § 203.31, one qualified deep well on the unitized portion of lease A (drilled after the ultra-deep well on the non-unitized portion of that lease) and a qualified phase 2 ultra-deep well on lease B that earns lease B a 35 BCF RSV under § 203.31. The participating area percentages allocate 40 percent of production from both of the unit qualified wells to lease A and 60 percent to lease B. If the non-unitized qualified phase 2 ultra-deep well on lease A produces 12 BCF, and the unitized qualified well on lease A produces 18 BCF, and the qualified well on lease B produces 37 BCF, then the production volume from and allocated to lease A to which the lease A RSV applies is 34 BCF [12 + (18 + 37)(0.40)]. The production volume allocated to lease B to which the lease B RSV applies is 33 BCF [(18 + 37)(0.60)]. None of the volumes produced from a well that is not within a unit participating area may be allocated to other leases in the unit.

(d) You must begin paying royalties when the cumulative production of gas from all qualified wells on your lease, or allocated to your lease under paragraph (b) of this section, reaches the applicable RSV allowed under § 203.31 or § 203.41. For the month in which cumulative production reaches this RSV, you owe royalties on the portion of gas production from or allocated to your lease that exceeds the RSV remaining at the beginning of that month.

§ 203.34 To which production may an RSV earned by qualified phase 2 and phase 3 ultra-deep wells on my lease not be applied?

You may not apply an RSV earned under § 203.31:

(a) To production from completions less than 15,000 feet TVD SS, except in cases where the qualified well is re-perforated in the same reservoir previously perforated deeper than 15,000 feet TVD SS;

(b) To production from a deep well or ultra-deep well on any other lease, except as provided in paragraph (c) of § 203.33;

(c) To any liquid hydrocarbon (oil and condensate) volumes; or

(d) To production from a deep well or ultra-deep well that commenced drilling before:

(1) March 26, 2003, on a lease that is located entirely or partly in water less than 200 meters deep; or

(2) May 18, 2007, on a lease that is located entirely in water more than 200 meters deep.

§ 203.35 What administrative steps must I take to use the RSV earned by a qualified phase 2 or phase 3 ultra-deep well?

To use an RSV earned under § 203.31:

(a) You must notify the MMS Regional Supervisor for Production and Development in writing of your intent to begin drilling operations on all your ultra-deep wells.

(b) Before beginning production, you must meet any production measurement requirements that the MMS Regional Supervisor for Production and Development has determined are necessary under 30 CFR Part 250, Subpart L.

(c)(1) Within 30 days of the beginning of production from any wells that would become qualified phase 2 or phase 3 ultra-deep wells by satisfying the requirements of this section:

(i) Provide written notification to the MMS Regional Supervisor for Production and Development that production has begun; and

(ii) Request confirmation of the size of the RSV earned by your lease.

(2) If you produced from a qualified phase 2 or phase 3 ultra-deep well before December 18, 2008, you must provide the information in paragraph (c)(1) of this section no later than January 20, 2009.

(d) If you cannot produce from a well that otherwise meets the criteria for a qualified phase 2 ultra-deep well that is an ultra-deep short sidetrack before May 3, 2009, on a lease that is located entirely or partly in water less than 200 meters deep, or before May 3, 2013, on a lease that is located entirely in water more than 200 meters but less than 400 meters deep, the MMS Regional Supervisor for Production and Development may extend the deadline for beginning production for up to 1 year, based on the circumstances of the particular well involved, if it meets all the following criteria.

(1) The delay occurred after drilling reached the total depth in your well.

(2) Production (other than test production) was expected to begin from the well before May 3, 2009, on a lease that is located entirely or partly in water less than 200 meters deep or before May 3, 2013, on a lease that is located entirely in water more than 200 meters but less than 400 meters deep. You must provide a credible activity schedule with supporting documentation.

(3) The delay in beginning production is for reasons beyond your control, such as adverse weather and accidents which MMS deems were unavoidable.

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

(a) You must pay royalties on all gas production to which an RSV otherwise would be applied under § 203.33 for any calendar year in which the average daily closing New York Mercantile Exchange (NYMEX) natural gas price exceeds the applicable threshold price shown in the following table.

A price threshold in year 2007 dollars of . . .	Applies to . . .
(1) $10.15 per MMBtu	(i) The first 25 BCF of RSV earned under § 203.31(a) by a phase 2 ultra-deep well on a lease that is located in water partly or entirely less than 200 meters deep issued before December 18, 2008; and (ii) Any RSV earned under § 203.31(b) by a phase 2 ultra-deep well.
(2) $4.55 per MMBtu	(i) Any RSV earned under § 203.31(a) by a phase 3 ultra-deep well unless the lease terms prescribe a different price threshold; (ii) The last 10 BCF of the 35 BCF of RSV earned under § 203.31(a) by a phase 2 ultra-deep well on a lease that is located in water partly or entirely less than 200 meters deep issued before December 18, 2008 and that is not a non-converted lease; (iii) The last 15 BCF of the 35 BCF of RSV earned under § 203.31(a) by a phase 2 ultra-deep well on a non-converted lease; (iv) Any RSV earned under § 203.31(a) by a phase 2 ultra-deep well on a lease in water partly or entirely less than 200 meters deep issued on or after December 18, 2008 unless the lease terms prescribe a different price threshold; and (v) Any RSV earned under § 203.31(a) by a phase 2 ultra-deep well on a lease in water entirely more than 200 meters deep and entirely less than 400 meters deep.

A price threshold in year 2007 dollars of . . .	Applies to . . .
(3) $4.08 per MMBtu	(i) The first 20 BCF of RSV earned by a well that is located on a non-converted lease issued in OCS Lease Sale 178.
(4) $5.83 per MMBtu	(i) The first 20 BCF of RSV earned by a well that is located on a non-converted lease issued in OCS Lease Sales 180, 182, 184, 185, or 187.

(b) For purposes of paragraph (a) of this section, determine the threshold price for any calendar year after 2007 by:

(1) Determining the percentage of change during the year in the Department of Commerce's implicit price deflator for the gross domestic product; and

(2) Adjusting the threshold price for the previous year by that percentage.

(c) The following examples illustrate how this section applies.

Example 1: Assume that a lessee drills and begins producing from a qualified phase 2 ultra-deep well in 2008 on a lease issued in 2004 in less than 200 meters of water that earns the lease an RSV of 35 BCF. Further, assume the well produces a total of 18 BCF by the end of 2009 and in both of those years, the average daily NYMEX closing natural gas price is less than $10.15 (adjusted for inflation after 2007). The lessee does not pay royalty on the 18 BCF because the gas price threshold under paragraph (a)(1) of this section applies to the first 25 BCF of this RSV earned by this phase 2 ultra-deep well. In 2010, the well produces another 13 BCF. In that year, the average daily closing NYMEX natural gas price is greater than $4.55 per MMBtu (adjusted for inflation after 2007), but less than $10.15 per MMBtu (adjusted for inflation after 2007). The first 7 BCF produced in 2010 will exhaust the first 25 BCF (that is subject to the $10.15 threshold) of the 35 BCF RSV that the well earned. The lessee must pay royalty on the remaining 6 BCF produced in 2010, because it is subject to the $4.55 per MMBtu threshold under paragraph (a)(2)(ii) of this section which was exceeded.

Example 2: Assume that a lessee:

(1) Drills and produces from well no.1, a qualified deep well in 2008 to a depth of 15,500 feet TVD SS that earns a 15 BCF RSV for the lease under § 203.41, which would be subject to a price threshold of $10.15 per MMBtu (adjusted for inflation after 2007), meaning the lease is partly or entirely in less than 200 meters of water;

(2) Later in 2008 drills and produces from well no. 2, a second qualified deep well to a depth of 17,000 feet TVD SS that earns no additional RSV (see § 203.41(c)(1)); and

(3) In 2015, drills and produces from well no. 3, a qualified phase 3 ultra-deep well that earns no additional RSV since the lease already has an RSV established by prior deep well production. Further assume that in 2015, the average daily closing NYMEX natural gas price exceeds $4.55 per MMBtu (adjusted for inflation after 2007) but does not exceed $10.15 per MMBtu (adjusted for inflation after 2007). In 2015, any remaining RSV earned by well no. 1 (which would have been applied to production from well nos. 1 and 2 in the intervening years), would be applied to production from all three qualified wells. Because the price threshold applicable to that RSV was not exceeded, the production from all three qualified wells would be royalty-free until the 15 BCF RSV earned by well no. 1 is exhausted.

Example 3: Assume the same initial facts regarding the three wells as in Example 2. Further assume that well no. 1 stopped producing in 2011 after it had produced 8 BCF, and that well no. 2 stopped producing in 2012 after it had produced 5 BCF. Two BCF of the RSV earned by well no. 1 remain. That RSV would be applied to production from well no. 3 until it is exhausted, and the lessee therefore would not pay royalty on those 2 BCF produced in 2015, because the $10.15 per MMBtu (adjusted for inflation after 2007) price threshold is not exceeded. The determination of which price threshold applies to deep gas production depends on when the first qualified well earned the RSV for the lease, not on which wells use the RSV.

Example 4: Assume that in February 2010 a lessee completes and begins producing from an ultra-deep well (at a depth of 21,500 feet TVD SS) on a lease located in 325 meters of water with no prior production from any deep well and no deep water royalty relief. The ultra-deep well would be a phase 2 ultra-deep well (see definition in § 203.0), and would earn the lease an RSV of 35 BCF under §§ 203.30 and 203.31. Further assume that the average daily closing NYMEX natural gas price exceeds $4.55 per MMBtu (adjusted for inflation after 2007) but does not exceed $10.15 per MMBtu (adjusted for inflation after 2007) during 2010. Because the lease is located in more than 200 but less than 400 meters of water, the $4.55 per MMBtu price threshold applies to the whole RSV (see paragraph (a)(2)(v) of this section), and the lessee will owe royalty on all gas produced from the ultra-deep well in 2010.

(d) You must pay any royalty due under this section no later than March 31 of the year following the calendar year for which you owe royalty. If you do not pay by that date, you must pay late payment interest under § 218.54 from April 1 until the date of payment.

(e) Production volumes on which you must pay royalty under this section count as part of your RSV.

■ 6. Revise §§ 203.40 and 203.41 to read as follows:

§ 203.40 Which leases are eligible for royalty relief as a result of drilling a deep well or a phase 1 ultra-deep well?

Your lease may receive an RSV under §§ 203.41 through 203.44, and may receive an RSS under §§ 203.45 through 203.47, if it meets all the requirements of this section.

(a) The lease is located in the GOM wholly west of 87 degrees, 30 minutes West longitude in water depths entirely less than 400 meters deep.

(b) The lease has not produced gas or oil from a well with a perforated interval the top of which is 18,000 feet TVD SS or deeper that commenced drilling either:

(1) Before March 26, 2003, on a lease that is located partly or entirely in water less than 200 meters deep; or

(2) Before May 18, 2007, on a lease that is located in water entirely more than 200 meters and entirely less than 400 meters deep.

(c) In the case of a lease located partly or entirely in water less than 200 meters deep, the lease was issued in a lease sale held either:

(1) Before January 1, 2001;

(2) On or after January 1, 2001, and before January 1, 2004, and, in cases where the original lease terms provided for an RSV for deep gas production, the lessee has exercised the option provided for in § 203.49; or

(3) On or after January 1, 2004, and the lease terms provide for royalty relief under §§ 203.41 through 203.47 of this part. (**Note:** Because the original § 203.41 has been divided into new §§ 203.41 and 203.42 and subsequent sections have been redesignated as §§ 203.43 through 203.48, royalty relief in lease terms for leases issued on or after January 1, 2004, should be read as referring to §§ 203.41 through 203.48.)

(d) If the lease is located entirely in more than 200 meters and less than 400 meters of water, it must either:

(1) Have been issued before November 28, 1995, and not been granted deep water royalty relief under 43 U.S.C. 1337(a)(3)(C), added by section 302 of the Deep Water Royalty Relief Act; or

(2) Have been issued after November 28, 2000, and not been granted deep water royalty relief under §§ 203.60 through 203.79.

§ 203.41 If I have a qualified deep well or a qualified phase 1 ultra-deep well, what royalty relief would my lease earn?

(a) To qualify for a suspension volume under paragraphs (b) or (c) of this section, your lease must meet the requirements in § 203.40 and the requirements in the following table.

If your lease has not . . .	And if it later . . .	Then your lease . . .
(1) produced gas or oil from any deep well or ultra-deep well,	has a qualified deep well or qualified phase 1 ultra-deep well,.	earns an RSV specified in paragraph (b) of this section.
(2) produced gas or oil from a well with a perforated interval whose top is 18,000 feet TVD SS or deeper,	has a qualified deep well with a perforated interval whose top is 18,000 feet TVD SS or deeper or a qualified phase 1 ultra-deep well,.	earns an RSV specified in paragraph (c) of this section.

(b) If your lease meets the requirements in paragraph (a)(1) of this section, it earns the RSV prescribed in the following table:

If you have a qualified deep well or a qualified phase 1 ultra-deep well that is:	Then your lease earns an RSV on this volume of gas production:
(1) An original well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	15 BCF.
(2) A sidetrack with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 15 BCF.
(3) An original well with a perforated interval the top of which is at least 18,000 feet TVD SS,	25 BCF.
(4) A sidetrack with a perforated interval the top of which is at least 18,000 feet TVD SS,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 25 BCF.

(c) If your lease meets the requirements in paragraph (a)(2) of this section, it earns the RSV prescribed in the following table. The RSV specified in this paragraph is in addition to any RSV your lease already may have earned from a qualified deep well with a perforated interval whose top is from 15,000 feet to less than 18,000 feet TVD SS.

If you have a qualified deep well or a qualified phase 1 ultra-deep well that is . . .	Then you earn an RSV on this amount of gas production:
(1) An original well or a sidetrack with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	0 BCF.
(2) An original well with a perforated interval the top of which is 18,000 feet TVD SS or deeper,	10 BCF.
(3) A sidetrack with a perforated interval the top of which is 18,000 feet TVD SS or deeper,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 10 BCF.

(d) Lessees may request a refund of or recoup royalties paid on production from qualified wells on a lease that is located in water entirely deeper than 200 meters but entirely less than 400 meters deep that:

(1) Occurs before December 18, 2008; and

(2) Is subject to application of an RSV under either § 203.31 or § 203.41.

(e) The following examples illustrate how this section applies, assuming your lease meets the location, prior production, and lease issuance conditions in § 203.40 and paragraph (a) of this section:

Example 1: If you have a qualified deep well that is an original well with a perforated interval the top of which is 16,000 feet TVD SS, your lease earns an RSV of 15 BCF under paragraph (b)(1) of this section. This RSV must be applied to gas production from all qualified wells on your lease, as prescribed in §§ 203.43 and 203.48. However, if the top of the perforated interval is 18,500 feet TVD SS, the RSV is 25 BCF according to paragraph (b)(3) of this section.

Example 2: If you have a qualified deep well that is a sidetrack, with a perforated interval the top of which is 16,000 feet TVD SS and a sidetrack measured depth of 6,789 feet, we round the measured depth to 6,800 feet and your lease earns an RSV of 8.08 BCF under paragraph (b)(2) of this section. This RSV would be applied to gas production from all qualified wells on your lease, as prescribed in §§ 203.43 and 203.48.

Example 3: If you have a qualified deep well that is a sidetrack, with a perforated interval the top of which is 16,000 feet TVD SS and a sidetrack measured depth of 19,500 feet, your lease earns an RSV of 15 BCF. This RSV would be applied to gas production from all qualified wells on your lease, as prescribed in §§ 203.43 and 203.48, even though 4 BCF plus 600 MCF per foot of sidetrack measured depth equals 15.7 BCF because paragraph (b)(2) of this section limits the RSV for a sidetrack at the amount an original well to the same depth would earn.

Example 4: If you have drilled and produced a deep well with a perforated interval the top of which is 16,000 feet TVD SS before March 26, 2003 (and the well therefore is not a qualified well and has earned no RSV under this section), and later drill:

(i) A deep well with a perforated interval the top of which is 17,000 feet TVD SS, your lease earns no RSV (see paragraph (c)(1) of this section);

(ii) A qualified deep well that is an original well with a perforated interval the top of which is 19,000 feet TVD SS, your lease earns an RSV of 10 BCF under paragraph (c)(2) of this section. This RSV would be applied to gas production from qualified wells on your lease, as prescribed in §§ 203.43 and 203.48; or

(iii) A qualified deep well that is a sidetrack with a perforated interval the top of which is 19,000 feet TVD SS, that has a sidetrack measured depth of 7,000 feet, your lease earns an RSV of 8.2 BCF under paragraph (c)(3) of this section. This RSV would be applied to gas production from qualified wells on your lease, as prescribed in §§ 203.43 and 203.48.

Example 5: If you have a qualified deep well that is an original well with a perforated interval the top of which is 16,000 feet TVD SS, and later drill a second qualified well that is an original well with a perforated interval the top of which is 19,000 feet TVD SS, we increase the total RSV for your lease from 15 BCF to 25 BCF under paragraph (c)(2) of this section. We will apply that RSV to gas production from all qualified wells on your lease, as prescribed in §§ 203.43 and 203.48. If the second well has a perforated interval the top of which is 22,000 feet TVD SS (instead of 19,000 feet), the total RSV for your lease would increase to 25 BCF only in 2 situations: (1) If the second well was a phase 1 ultra-deep well, i.e., if drilling began before May 18, 2007, or (2) the exception in § 203.31(b) applies. In both situations, your lease must be partly or entirely in less than 200 meters of water and production must begin on this well before May 3, 2009. If drilling of the second well began on or after May 18, 2007, the second well would be qualified as a phase 2 or phase 3 ultra-deep well and, unless the exception in § 203.31(b) applies, would not earn any additional RSV (as prescribed in § 203.30), so the total RSV for your lease would remain at 15 BCF.

Example 6: If you have a qualified deep well that is a sidetrack, with a perforated interval the top of which is 16,000 feet TVD SS and a sidetrack measured depth of 4,000 feet, and later drill a second qualified well that is a sidetrack, with a perforated interval the top of which is 19,000 feet TVD SS and a sidetrack measured depth of 8,000 feet, we increase the total RSV for your lease from 6.4 BCF [4 + (600 * 4,000)/1,000,000] to 15.2 BCF {6.4 + [4 + (600 * 8,000)/1,000,000)]} under paragraphs (b)(2) and (c)(3) of this section. We would apply that RSV to gas production from all qualified wells on your lease, as prescribed in §§ 203.43 and 203.48. The difference of 8.8 BCF represents the RSV earned by the second sidetrack that has a perforated interval the top of which is deeper than 18,000 feet TVD SS.

■ 7. Sections 203.42 through 203.48 are redesignated as §§ 203.42 through 203.49.

■ 8. Add new § 203.42 to read as follows:

§ 203.42 What conditions and limitations apply to royalty relief for deep wells and phase 1 ultra-deep wells?

The conditions and limitations in the following table apply to royalty relief under § 203.41.

If . . .	Then . . .
(a) Your lease has produced gas or oil from a well with a perforated interval the top of which is 18,000 feet TVD SS or deeper,	your lease cannot earn an RSV under § 203.41 as a result of drilling any subsequent deep wells or phase 1 ultra-deep wells.
(b) You determine RSV under § 203.41 for the first qualified deep well or qualified phase 1 ultra-deep well on your lease (whether an original well or a sidetrack) because you drilled and produced it within the time intervals set forth in the definitions for qualified wells,	that determination establishes the total RSV available for that drilling depth interval on your lease (i.e., either 15,000–18,000 feet TVD SS, or 18,000 feet TVD SS and deeper), regardless of the number of subsequent qualified wells you drill to that depth interval.
(c) A qualified deep well or qualified phase 1 ultra-deep well on your lease is within a unitized portion of your lease,	the RSV earned by that well under § 203.41 applies only to production from qualified wells on or allocated to your lease and not to other leases within the unit.
(d) Your qualified deep well or qualified phase 1 ultra-deep well is a directional well (either an original well or a sidetrack) drilled across a lease line,	the lease with the perforated interval that initially produces earns the RSV. However, if the perforated interval crosses a lease line, the lease where the surface of the well is located earns the RSV.
(e) You earn an RSV under § 203.41,	that RSV is in addition to any RSS for your lease under § 203.45 that results from a different wellbore.
(f) Your lease earns an RSV under § 203.41 and later produces from a well that is not a qualified well,	the RSV is not forfeited or terminated, but you may not apply the RSV under § 203.41 to production from the non-qualified well.
(g) You qualify for an RSV under paragraphs (b) or (c) of § 203.41,	you still owe minimum royalties or rentals in accordance with your lease terms.
(h) You transfer your lease,	unused RSVs transfer to a successor lessee and expire with the lease.

Example to paragraph (b): If your first qualified deep well is a sidetrack with a perforated interval whose top is 16,000 feet TVD SS and earns an RSV of 12.5 BCF, and you later drill a qualified original deep well to 17,000 feet TVD SS, the RSV for your lease remains at 12.5 BCF and does not increase to 15 BCF. However, under paragraph (c) of § 203.41, if you subsequently drill a qualified deep well to a depth of 18,000 feet or greater TVD SS, you may earn an additional RSV.

■ 9. Revise newly redesignated § 203.43 to read as follows:

§ 203.43 To which production do I apply the RSV earned from qualified deep wells or qualified phase 1 ultra-deep wells on my lease?

(a) You must apply the RSV prescribed in § 203.41(b) and (c) to gas volumes produced from qualified wells on or after May 3, 2004, reported on the OGOR–A for your lease under § 216.53, as and to the extent prescribed in §§ 203.43 and 203.48.

(1) Except as provided in paragraph (a)(2) of this section, all gas production from qualified wells reported on the OGOR–A, including production that is not subject to royalty, counts toward the lease RSV.

(2) Production to which an RSS applies under §§ 203.45 and 203.46 does not count toward the lease RSV.

(b) This paragraph applies to any lease with a qualified deep well or qualified phase 1 ultra-deep well when no part of the lease is within an MMS-approved unit. Subject to the price conditions in § 203.48, you must apply the RSV prescribed in § 203.41 as required under the following paragraphs (b)(1) and (b)(2) of this section.

(1) You must apply the RSV to the earliest gas production occurring on and after the later of:

(i) May 3, 2004, for an RSV earned by a qualified deep well or qualified phase 1 ultra-deep well on a lease that is located entirely or partly in water less than 200 meters deep;

(ii) May 18, 2007, for an RSV earned by a qualified deep well on a lease that is located entirely in water more than 200 meters deep; or

(iii) The date that the first qualified well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production from qualified wells on your lease, regardless of their depth, for which you have met the requirements in § 203.35 or § 203.44.

Example 1: On a lease in water less than 200 meters deep, you began drilling an original deep well with a perforated interval the top of which is 18,200 feet TVD SS in September 2003, that became a qualified deep well in July 2004, when it began producing and using the RSV that it earned. You subsequently drill another original deep well with a perforated interval the top of which is 16,600 feet TVD SS, which becomes a qualified deep well when production begins in August 2008. The first well earned an RSV of 25 BCF (see § 203.41(a)(1) and (b)(3)). You must apply any remaining RSV each month beginning in August 2008 to production from both wells until the 25 BCF RSV is fully utilized according to paragraph (b)(2) of this section. If the second well had begun production in August 2009, it would not be a qualified deep well because it started production after expiration in May 2009 of the ability to qualify for royalty relief in this water depth, and could not share any of the remaining RSV (see definition of a qualified deep well in § 203.0).

Example 2: On a lease in water between 200 and 400 meters deep, you begin drilling an original deep well with a perforated interval the top of which is 17,100 feet TVD SS in November 2010 that becomes a qualified deep well in June 2011 when it begins producing and using the RSV. You subsequently drill another original deep well with a perforated interval the top of which is 15,300 feet TVD SS which becomes a qualified deep well by beginning production in October 2011 (see definition of a qualified deep well in § 203.0). Only the first well earns an RSV equal to 15 BCF (*see* § 203.41(a) and (b)). You must apply any remaining RSV each month beginning in October 2011 to production from both qualified deep wells until the 15 BCF RSV is fully utilized according to paragraph (b)(2) of this section.

(c) This paragraph applies to any lease with a qualified deep well or qualified phase 1 ultra-deep well when all or part of the lease is within an MMS-approved unit. Under the unit agreement, a share of the production from all the qualified wells in the unit participating area would be allocated to your lease each month according to the participating area percentages. Subject to the price conditions in § 203.48, you must apply the RSV prescribed under § 203.41 as required under the following paragraphs (c)(1) through (c)(3) of this section.

(1) You must apply the RSV to the earliest gas production occurring on and after the later of:

(i) May 3, 2004, for an RSV earned by a qualified well or qualified phase 1 ultra-deep well on a lease that is located entirely or partly in water less than 200 meters deep;

(ii) May 18, 2007, for an RSV earned by a qualified deep well on a lease that is located entirely in water more than 200 meters deep; or

(iii) The date that the first qualified well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production:

(i) From all qualified wells on the non-unitized area of your lease, regardless of their depth, for which you have met the requirements in § 203.35 or § 203.44; and,

(ii) Allocated to your lease under an MMS-approved unit agreement from qualified wells on unitized areas of your lease and on unitized areas of other leases in the unit, regardless of their depth, for which the requirements in § 203.35 or § 203.44 have been met.

(3) The allocated share under paragraph (c)(2)(ii) of this section does not increase the RSV for your lease. None of the volumes produced from a well that is not within a unit participating area may be allocated to other leases in the unit.

Example: The east half of your lease A is unitized with all of lease B. There is one qualified 19,000-foot TVD SS deep well on the non-unitized portion of lease A, one qualified 18,500-foot TVD SS deep well on the unitized portion of lease A, and a qualified 19,400-foot TVD SS deep well on lease B. The participating area percentages allocate 32 percent of production from both of the unit qualified deep wells to lease A and 68 percent to lease B. If the non-unitized qualified deep well on lease A produces 12 BCF and the unitized qualified deep well on lease A produces 15 BCF, and the qualified deep well on lease B produces 10 BCF, then the production volume from and allocated to lease A to which the lease an RSV applies is 20 BCF [12 + (15 + 10) * (0.32)]. The production volume allocated to lease B to which the lease B RSV applies is 17 BCF [(15 + 10) * (0.68)].

(d) You must begin paying royalties when the cumulative production of gas from all qualified wells on your lease, or allocated to your lease under paragraph (c) of this section, reaches the applicable RSV allowed under § 203.31 or § 203.41. For the month in which cumulative production reaches this RSV, you owe royalties on the portion of gas production that exceeds the RSV remaining at the beginning of that month.

(e) You may not apply the RSV allowed under § 203.41 to:

(1) Production from completions less than 15,000 feet TVD SS, except in cases where the qualified deep well is re-perforated in the same reservoir previously perforated deeper than 15,000 feet TVD SS;

(2) Production from a deep well or phase 1 ultra-deep well on any other lease, except as provided in paragraph (c) of this section;

(3) Any liquid hydrocarbon (oil and condensate) volumes; or

(4) Production from a deep well or phase 1 ultra-deep well that commenced drilling before:

(i) March 26, 2003, on a lease that is located entirely or partly in water less than 200 meters deep, or

(ii) May 18, 2007, on a lease that is located entirely in water more than 200 meters deep.

■ 10. In redesignated § 203.44, paragraphs (a), (d), and (e) are revised to read as follows:

§ 203.44 What administrative steps must I take to use the RSV earned by a qualified deep well or qualified phase 1 ultra-deep well?

(a) You must notify the MMS Regional Supervisor for Production and Development in writing of your intent to begin drilling operations on all deep wells and phase 1 ultra-deep wells; and

* * * * *

(d) You must provide the information in paragraph (b) of this section by January 20, 2009 if you produced before December 18, 2008 from a qualified deep well or qualified phase 1 ultra-deep well on a lease that is located entirely in water more than 200 meters and less than 400 meters deep.

(e) The MMS Regional Supervisor for Production and Development may extend the deadline for beginning production for up to one year for a well that cannot begin production before the applicable date prescribed in the definition of ''qualified deep well'' in § 203.0 if it meets all of the following criteria.

(1) The well otherwise meets the criteria in the definition of a qualified deep well in § 203.0.

(2) The delay in production occurred after reaching total depth in the well.

(3) Production (other than test production) was expected to begin from the well before the applicable deadline in the definition of a qualified deep well in § 203.0. You must provide a credible activity schedule with supporting documentation.

(4) The delay in beginning production is for reasons beyond your control, such as adverse weather and accidents which MMS deems were unavoidable.

■ 11. In redesignated § 203.45, paragraphs (a), (b) and (e) are revised to read as follows:

§ 203.45 If I drill a certified unsuccessful well, what royalty relief will my lease earn?

* * * * *

(a) If you drill a certified unsuccessful well and you satisfy the administrative requirements of § 203.47, subject to the price conditions in § 203.48, your lease earns an RSS shown in the following table. The RSS is shown in billions of cubic feet of gas equivalent (BCFE) or in thousands of cubic feet of gas equivalent (MCFE) and is applicable to oil and gas production as prescribed in § 204.46.

If you have a certified unsuccessful well that is:	Then your lease earns an RSS on this volume of oil and gas production as prescribed in this section and § 203.46:
(1) An original well and your lease has not produced gas or oil from a deep well or an ultra-deep well,	5 BCFE.
(2) A sidetrack (with a sidetrack measured depth of at least 10,000 feet) and your lease has not produced gas or oil from a deep well or an ultra-deep well,	0.8 BCFE plus 120 MCFE times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 5 BCFE.
(3) An original well or a sidetrack (with a sidetrack measured depth of at least 10,000 feet) and your lease has produced gas or oil from a deep well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	2 BCFE.

(b) This paragraph applies to oil and gas volumes you report on the OGOR–A for your lease under § 216.53.

(1) You must apply the RSS prescribed in paragraph (a) of this section, in accordance with the requirements in § 203.46, to all oil and gas produced from the lease:

(i) On or after December 18, 2008, if your lease is located in water more than 200 meters but less than 400 meters deep; or

(ii) On or after May 3, 2004, if your lease is located in water partly or entirely less than 200 meters deep.

(2) Production to which an RSV applies under §§ 203.31 through 203.33 and §§ 203.41 through 203.43 does not count toward the lease RSS. All other production, including production that is not subject to royalty, counts toward the lease RSS.

Example 1: If you drill a certified unsuccessful well that is an original well to a target 19,000 feet TVD SS, your lease earns an RSS of 5 BCFE that would be applied to gas and oil production if your lease has not previously produced from a deep well or an ultra-deep well, or you earn an RSS of 2 BCFE of gas and oil production if your lease has previously produced from a deep well with a perforated interval from 15,000 to less than 18,000 feet TVD SS, as prescribed in § 203.46.

Example 2: If you drill a certified unsuccessful well that is a sidetrack that reaches a target 19,000 feet TVD SS, that has a sidetrack measured depth of 12,545 feet, and your lease has not produced gas or oil from any deep well or ultra-deep well, MMS rounds the sidetrack measured depth to 12,500 feet and your lease earns an RSS of 2.3 BCFE of gas and oil production as prescribed in § 203.45.

* * * * *

(e) If the same wellbore that earns an RSS as a certified unsuccessful well later produces from a perforated interval the top of which is 15,000 feet TVD or deeper and becomes a qualified well, it will be subject to the following conditions:

* * * * *

■ 12. In redesignated § 203.46, paragraphs (a) introductory text, (a)(1), (c), and (e) are revised to read as follows:

§ 203.46 To which production do I apply the RSS from drilling one or two certified unsuccessful wells on my lease?

(a) Subject to the requirements of §§ 203.40, 203.43, 203.45, 203.47, and 203.48, you must apply an RSS in § 203.45 to the earliest oil and gas production:

(1) Occurring on and after the day you file the information under § 204.47(b),

* * * * *

(c) If you have no current production on which to apply the RSS allowed under § 203.45, your RSS applies to the earliest subsequent production of gas and oil from, or allocated under an MMS-approved unit agreement to, your lease.

* * * * *

(e) You may not apply the RSS allowed under § 203.45 to production from any other lease, except for production allocated to your lease from an MMS-approved unit agreement. If your certified unsuccessful well is on a lease subject to an MMS-approved unit agreement, the lessees of other leases in the unit may not apply any portion of the RSS for your lease to production from the other leases in the unit.

* * * * *

■ 13. In redesignated § 203.47, paragraph (c) is revised to read as follows:

§ 203.47 What administrative steps do I take to obtain and use the royalty suspension supplement?

* * * * *

(c) If you commenced drilling a well that otherwise meets the criteria for a certified unsuccessful well on a lease located entirely in more than 200 meters and entirely less than 400 meters of water on or after May 18, 2007, and finished it before December 18, 2008, you must provide the information in paragraph (b) of this section no later than February 17, 2009.

■ 14. Redesignated § 203.48 is revised to read as follows:

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

(a) You must pay royalties on all gas and oil production for which an RSV or an RSS otherwise would be allowed under §§ 203.40 through 203.47 for any calendar year when the average daily closing NYMEX natural gas price exceeds the applicable threshold price shown in the following table.

For a lease located in water . . .	And issued . . .	the applicable threshold price is . . .
(1) Partly or entirely less than 200 meters deep,	before December 18, 2008,	$10.15 per MMBtu, adjusted annually after calendar year 2007 for inflation.
(2) Partly or entirely less than 200 meters deep,	after December 18, 2008,	$4.55 per MMBtu, adjusted annually after calendar year 2007 for inflation unless the lease terms prescribe a different price threshold.
(3) Entirely more than 200 meters and entirely less than 400 meters deep,	on any date,	$4.55 per MMBtu, adjusted annually after calendar year 2007 for inflation unless the lease terms prescribe a different price threshold.

(b) Determine the threshold price for any calendar year after 2007 by adjusting the threshold price in the previous year by the percentage that the implicit price deflator for the gross domestic product, as published by the Department of Commerce, changed during the calendar year.

(c) You must pay any royalty due under this section no later than March 31 of the year following the calendar year for which you owe royalty. If you do not pay by that date, you must pay late payment interest under § 218.54 from April 1 until the date of payment.

(d) Production volumes on which you must pay royalty under this section count as part of your RSV and RSS.

■ 15. In redesignated § 203.49, the introductory text in paragraph (a) and paragraph (c) are revised to read as follows:

§ 203.49 May I substitute the deep gas drilling provisions in this part for the deep gas royalty relief provided in my lease terms?

(a) You may exercise an option to replace the applicable lease terms for royalty relief related to deep-well drilling with those in § 203.0 and §§ 203.40 through 203.48 if you have a lease issued with royalty relief provisions for deep-well drilling. Such leases:

* * * * *

(c) Once you exercise the option under paragraph (a) of this section, you are subject to all the activity, timing, and administrative requirements pertaining to deep gas royalty relief as specified in §§ 203.40 through 203.48.

* * * * *

■ 16. The undesignated center heading between § 203.56 and § 203.60 is revised to read as follows:

Royalty Relief for Pre-Act Deep Water Leases and for Development and Expansion Projects

■ 17. Revise § 203.60 to read as follows:

§ 203.60 Who may apply for royalty relief on a case-by-case basis in deep water in the Gulf of Mexico or offshore of Alaska?

You may apply for royalty relief under §§ 203.61(b) and 203.62 for an individual lease, unit or project if you:

(a) Hold a pre-Act lease (as defined in § 203.0) that we have assigned to an authorized field (as defined in § 203.0);

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

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

■ 18. Revise § 203.62 to read as follows:

§ 203.62 How do I apply for relief?

(a) You must send a complete application and the required fee to the MMS Regional Director for your region.

(b) Your application for royalty relief offshore Alaska or in deep water in the GOM must include an original and two copies (one set of digital information) of:

(1) Administrative information report;

(2) Economic Viability and relief justification report;

(3) G&G report;

(4) Engineering report;

(5) Production report; and

(6) Cost report.

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

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

■ 19. In § 203.69, paragraph (b) is revised, paragraphs (c) through (f) are redesignated as paragraphs (f) through (i), and new paragraphs (c) through (e) are added to read as follows:

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

* * * * *

(b) For development projects, any relief we grant applies only to project wells and replaces the royalty relief, if any, with which we issued your lease.

(c) If your project is economic given the royalty relief with which we issued your lease, we will reject the application.

(d) If the lease has earned or may earn deep gas royalty relief under §§ 203.40 through 203.49 or ultra-deep gas royalty relief under §§ 203.30 through 203.36, we will take the deep gas royalty relief or ultra-deep gas royalty relief into account in determining whether further royalty relief for a development project is necessary for production to be economic.

(e) If neither paragraph (c) nor (d) of this section apply, the *minimum* royalty suspension volumes are as shown in the following table:

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

* * * * *

■ 20. In § 203.70, revise the introductory text and paragraph (b) to read as follows:

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

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

Required report	When due to MMS	Due date extensions
* *	* *	* * *
(b) Post-production report	Within 120 days after the start of production that is subject to the approved royalty suspension volume.	With acceptable justification from you, the MMS Regional Director for your region may extend the due date up to 30 days.

■ 21. Revise § 203.77 to read as follows:

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

Yes, you may voluntarily give up relief by sending a letter to that effect to the MMS Regional office for your region.

■ 22. Revise § 203.78 to read as follows:

§ 203.78 Do I keep relief approved by MMS under §§ 203.60–203.77 for my lease, unit or project if prices rise significantly?

If prices rise above a base price threshold for light sweet crude oil or natural gas, you must pay full royalties on production otherwise subject to royalty relief approved by MMS under §§ 203.60–203.77 for your lease, unit or project as prescribed in this section.

(a) The following table shows the base price threshold for various types of leases, subject to paragraph (b) of this section. Note that, for post-November 2000 deepwater leases in the GOM, price thresholds apply on a lease basis, so different leases on the same development project or expansion project approved for royalty relief may have different price thresholds.

For . . .	The base price threshold is . . .
(1) Pre-Act leases in the GOM,	set by statute.
(2) Post-November 2000 deep water leases in the GOM or leases offshore of Alaska for which the lease or Notice of Sale set a base price threshold,	indicated in your original lease agreement or, if none, those in the Notice of Sale under which your lease was issued.
(3) Post-November 2000 deep water leases in the GOM or leases offshore of Alaska for which the lease or Notice of Sale did not set a base price threshold,	the threshold set by statute for pre-Act leases.

(b) An exception may occur if we determine that the price thresholds in paragraphs (a)(2) or (a)(3) mean the royalty suspension volume set under § 203.69 and in lease terms would provide inadequate encouragement to increase production or development, in which circumstance we could specify a different set of price thresholds on a case-by-case basis.

(c) Suppose your base oil price threshold set under paragraph (a) is $28.00 per barrel, and the daily closing NYMEX light sweet crude oil prices for the previous calendar year exceeds $28.00 per barrel, as adjusted in paragraph (h) of this section. In this case, we retract the royalty relief authorized in this subpart and you must:

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

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

(d) Suppose your base gas price threshold set under paragraph (a) is $3.50 per million British thermal units (Btu), and the daily closing NYMEX light sweet crude oil prices for the previous calendar year exceeds $3.50 per million Btu, as adjusted in paragraph (h) of this section. In this case, we retract the royalty relief authorized in this subpart and you must:

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

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

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

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

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

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

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

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

■ 23. In § 203.79, revise the section heading to read as follows:

§ 203.79 How do I appeal MMS's decisions related to royalty relief for a deepwater lease or a development or expansion project?

* * * * *

■ 24. In § 203.80, revise the section heading and introductory text to read as follows:

§ 203.80 When can I get royalty relief if I am not eligible for royalty relief under other sections in the subpart?

We may grant royalty relief when it serves the statutory purposes summarized in § 203.1 and our formal relief programs, including but not limited to the applicable levels of the royalty suspension volumes and price thresholds, provide inadequate encouragement to promote development or increase production. Unless your lease lies offshore of Alaska or wholly west of 87 degrees, 30 minutes West longitude in the GOM, your lease must be producing to qualify for relief. Before you may apply for royalty relief apart from our programs for end-of-life leases or for pre-Act deep water leases and development and expansion projects, we must agree that your lease or project has two or more of the following characteristics:

* * * * *

■ 25. In § 203.81, revise paragraph (b) to read as follows:

§ 203.81 What supplemental reports do royalty relief applications require?

* * * * *

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

* * * * *

■ 26. In § 203.89, revise the section heading to read as follows:

§ 203.89 What is in a cost report?

* * * * *

■ 27. In § 203.90, revise paragraph (b) to read as follows:

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

* * * * *

(b) A letter from the contractor building the system to the MMS Regional Director for your region certifying when construction started on your system; and

* * * * *

PART 260—OUTER CONTINENTAL SHELF OIL AND GAS LEASING

■ 28. The authority citation for part 260 continues to read as follows:

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

■ 29. In § 260.121, revise paragraph (b) to read as follows:

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

* * * * *

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

(1) In the Gulf of Mexico, in water 200 meters or deeper, and wholly west of 87 degrees, 30 minutes West longitude; or

(2) Offshore of Alaska.

* * * * *

■ 30. In § 260.122, remove paragraph (d) and revise paragraph (b)(1) to read as follows:

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

* * * * *

(b)(1) Notwithstanding any royalty suspension volume 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 price on the New York Mercantile Exchange (NYMEX) for light sweet crude oil exceeds the applicable threshold price of $36.39 per barrel, adjusted annually after calendar year 2007 for inflation unless the lease terms prescribe a different price threshold.

(ii) Any natural gas produced for any period stipulated in the lease during which the arithmetic average of the daily closing price on the NYMEX for natural gas exceeds the applicable threshold price of $4.55 per MMBtu, adjusted annually after calendar year 2007 for inflation unless the lease terms prescribe a different price threshold.

(iii) Determine the threshold price for any calendar year after 2007 by adjusting the threshold price in the previous year by the percentage that the implicit price deflator for the gross domestic product, as published by the Department of Commerce, changed during the calendar year.

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