SW., Atlanta, Georgia 30303–8960. The telephone number is (404) 562–9029. Ms. Spann can be reached via electronic mail at *spann.jane@epa.gov*.

SUPPLEMENTARY INFORMATION: For additional information see the direct final rule which is published in the Rules Section of this **Federal Register**. A detailed rationale for the approval is set forth in the direct final rule. If no adverse comments are received in response to this rule, no further activity is contemplated. If EPA receives adverse comments, the direct final rule will be withdrawn and all public comments received will be addressed in a subsequent final rule based on this proposed rule. EPA will not institute a second comment period on this document. Any parties interested in commenting on this document should do so at this time.

Dated: April 9, 2015.

Heather McTeer Toney,

Regional Administrator, Region 4.

[FR Doc. 2015–09049 Filed 4–20–15; 8:45 am]

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DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Part 3100

[LLWO3100 L13100000.PP0000]

RIN 1004–AE41

Oil and Gas Leasing; Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessments

AGENCY: Bureau of Land Management, Interior.

ACTION: Advance notice of proposed rulemaking.

SUMMARY: The Bureau of Land Management (BLM) is issuing this Advanced Notice of Proposed Rulemaking (ANPR) to solicit public comments and suggestions that may be used to update the BLM's regulations related to royalty rates, annual rental payments, minimum acceptable bids, bonding requirements, and civil penalty assessments for Federal onshore oil and gas leases. As explained below, each of these elements is important to the appropriate management of the public's oil and gas resources. They help ensure a fair return to the taxpayer, diligent development of leased resources, adequate reclamation when development is complete; and that there is adequate deterrence for violations of legal requirements, including trespass and unauthorized removal. Aspects of these elements are fixed by statute and beyond the Secretary's authority to revise; however, in many instances they have been further constrained by regulatory provisions (*e.g.,* minimum bond amounts) that have not been reviewed or adjusted in decades. The purpose of this ANPR is to seek comments on this situation and the need for, and content of, potential changes or updates to the existing regulations in these areas.

Specifically, the BLM is seeking comments and suggestions that would assist the agency in preparing a proposed rule that gives the Secretary of the Interior (Secretary), through the BLM, the flexibility to adjust royalty rates in response to changes in the oil and gas market. Absent near-term enactment of new statutory flexibility for new non-competitively issued leases, a future proposed rule would limit any contemplated royalty rate changes to new competitively issued oil and gas leases on BLM-managed lands, because the royalty rate that is charged on non-competitively issued leases is currently fixed by statute at 12.5 percent. The intent of any anticipated changes to the royalty rate regulations would be to provide the BLM with the necessary tools to ensure that the American people receive a fair return on the oil and gas resources extracted from BLM-managed lands.

In addition to the royalty rate, the BLM is also seeking input on: (1) How to update its annual rental payment, minimum acceptable bid, and bonding requirements for oil and gas leases, and (2) Whether to remove the caps established by existing regulations on civil penalties that may be assessed under the Federal Oil and Gas Royalty Management Act (FOGRMA). With respect to annual rental payments, the intent of any potential increase in annual payments would be to provide a greater financial incentive for oil and gas companies to develop their leases promptly or relinquish them, including for potential re-leasing, as appropriate, by other parties, and to ensure that leases acquired non-competitively provide a fair financial return to the taxpayer. With respect to the minimum acceptable bid, the intent of any potential changes is to ensure that the American taxpayers receive a fair financial return at BLM oil and gas lease sale auctions. With respect to bonding requirements, the intent of any potential bonding updates would be to ensure that bonds required for oil and gas activities on public lands adequately capture costs associated with potential non-compliance with any terms and conditions applicable to a Federal onshore oil and gas lease. The BLM's existing regulations currently set bond minimums that have not been adjusted in 50 years. With respect to penalty assessments, the intent of the potential removal of the regulatory caps would be to ensure that the penalties provide adequate deterrence of unlawful conduct, particularly drilling on Federal onshore leases without authorization and drilling into leased parcels in knowing and willful trespass.

The anticipated updates to BLM's onshore oil and gas royalty rate regulations and other potential changes to its standard lease fiscal terms address recommendations from the Government Accountability Office (GAO), and will help ensure that taxpayers are receiving a fair return from the development of these resources. The anticipated changes to the royalty rate regulations will also support implementation of reform proposals in the Administration's Fiscal Year (FY) 2016 budget.

DATES: The BLM will accept comments and suggestions on this ANPR on or before June 5, 2015.

ADDRESSES: You may submit comments by any of the following methods:

Mail: Director (630) Bureau of Land Management, U.S. Department of the Interior, 1849 C St. NW., Room 2134LM, Washington, DC 20240, Attention: 1004–AE41.

Personal or messenger delivery: U.S. Department of the Interior, Bureau of Land Management, 20 M Street SE., Room 2134LM, Attention: Regulatory Affairs, Washington, DC 20003.

Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the instructions at this Web site.

FOR FURTHER INFORMATION CONTACT: Dylan Fuge, Office of the Director, at 202–208–5235, Steven Wells, Division of Fluid Minerals, at 202–912–7143, or Jully McQuilliams, Division of Fluid Minerals, at 202–912–7156, for information regarding the substance of this ANPR. For information on procedural matters or the rulemaking process generally, you may contact Anna Atkinson, Regulatory Affairs, at 202–912–7438. Persons who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339, 24 hours a day, 7 days a week to contact the above individuals.

SUPPLEMENTARY INFORMATION: The Department of the Interior (Department) oversees and manages much of the nation's Federal mineral resources, including onshore oil and natural gas located on the 245 million surface acres and 700 million subsurface acres managed by the BLM. It is responsible for ensuring that the development of those resources occurs in an environmentally-responsible manner, while also meeting the nation's energy needs. Key components of the Department's management responsibility are ensuring that: (1) The American public receives a fair return from the production of those resources; (2) Issued leases are developed diligently and responsibly; (3) There are adequate financial measures in place to address the risks associated with development; and (4) Appropriate civil penalty provisions are in place to address violations of applicable legal requirements.

With respect to fair return, the BLM recognizes there is a need to periodically assess the onshore oil and gas fiscal system and review existing regulations and policies related to onshore royalty rates and minimum acceptable bids. With respect to diligent development, the BLM believes it may be appropriate to increase annual rental payments to provide a greater incentive for lessees to develop leases promptly or relinquish them so that they may be re-leased to other parties, as appropriate. With respect to lessees' financial assurance obligations, there may be a need to update existing bonding requirements to ensure that the bonds provide adequate resources to reclaim and restore lands and surface resources affected by leasing activities and development. With respect to civil penalty assessments, there may be a need to ensure that civil penalties adequately deter the unauthorized removal of or trespass on leased Federal oil and gas resources, which unlawfully deprive both the taxpayers and the lessees of the leased resources or their value.

The purpose of this ANPR is to solicit public comments and suggestions that would be helpful to the BLM in preparing a subsequent proposed rule, as well as to gather input that is needed to update onshore royalty rates, annual rental payments, the minimum acceptable bid, bonding requirements, and caps on civil penalty assessments. The scope of the anticipated proposed rule is likely to include a combination of existing BLM onshore oil and gas regulations and policies, including onshore royalty rates, oil and gas lease rental payments, minimum acceptable bids, and bonding requirements, and civil penalty assessments. See section III of this ANPR for a list of specific questions relating to these topics.

I. Public Comment Procedures

Commenting on the ANPR

You may submit comments on the ANPR by mail, personal or messenger delivery, or electronic mail.

Mail: Director (630) Bureau of Land Management, U.S. Department of the Interior, 1849 C St. NW., Room 2134LM, Washington, DC 20240, Attention: Regulatory Affairs, 1004–AE41.

Personal or messenger delivery: U.S. Department of the Interior, Bureau of Land Management, 20 M Street SE., Room 2134LM, Attention: Regulatory Affairs, Washington, DC 20003.

Electronic mail: You may access and comment on the ANPR at the Federal eRulemaking Portal by following the instructions at that site (see ADDRESSES).

Written comments and suggestions should:

—Be specific;
—Explain the reasoning behind your comments and suggestions; and
—Address the issues outlined in the ANPR.

For comments and suggestions to be the most useful, and most likely to inform decisions on the content of any proposed rule, they should:

—Be substantive; and
—Facilitate the development and implementation of an environmentally and fiscally responsible process for leasing public lands for oil and gas production.

The BLM is particularly interested in receiving comments and suggestions in response to the questions listed in section III of this ANPR. These specific questions will focus the feedback on matters most in need of public input for the development of the regulations. This public input will assist the BLM in considering and proposing appropriate adjustments to onshore lease royalty rates, annual rental payments, minimum acceptable bids, bonding requirements, and civil penalty or other assessments. All communications on these topics should refer to RIN 1004–AE41 and may be submitted by the methods listed under the ADDRESSES section of this ANPR.

Comments received after the close of the comment period (see DATES section of this ANPR) may not necessarily be considered or included in the Administrative Record for the proposed rule. Likewise, comments delivered to an address other than those listed under the ADDRESSES section of this ANPR may not necessarily be considered or included in the Administrative Record for the proposed rule.

Reviewing Comments Submitted by Others

Comments, including names and street addresses of respondents, will be available for public review at the personal or messenger delivery address listed under ADDRESSES during regular business hours (7:45 a.m. to 4:15 p.m.), Monday through Friday, except Federal holidays. They will also be available at the Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the instructions at this Web site for submitting, accessing, and/or reviewing comments.

Before including your address, telephone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

II. Background

Onshore Royalty Rates

The Mineral Leasing Act of 1920, as amended (30 U.S.C. 181 *et seq.*) (MLA), the Mineral Leasing Act for Acquired Lands of 1947, as amended (30 U.S.C. 351 *et seq.*) (MLAAL), and other statutes pertaining to specific categories of land authorize the Secretary to lease Federal oil and gas resources. The MLA and MLAAL prescribe the minimum percentage of royalty reserved to the United States under an onshore oil and gas lease on most Federal lands, as discussed further below. The BLM is responsible for regulating onshore leasing activities for BLM-managed lands and subsurface estate.

These authorities are implemented by the BLM through regulations at 43 CFR 3100. The BLM utilizes both competitive and non-competitive leasing processes. Pursuant to the Federal Onshore Oil and Gas Leasing Reform Act of 1987 (FOOGLRA), which amended the MLA, the BLM must first offer parcels on a competitive basis.[1] Leases are issued to the highest qualified bidder as determined by an auction process.[2] Parcels that do not

[1] The MLA, as amended by the FOOGLRA, directs the BLM to hold lease sales in each State where eligible lands are available for leasing at least quarterly. 30 U.S.C. 226(b)(1)(A).

[2] Under the MLA, lease sale auctions were, until recently, required to be conducted by oral bidding. *Id.* In 2014, the National Defense Authorization Act for Fiscal Year 2015 gave the BLM the authority for the first time to hold Internet auctions. Public Law

Continued

receive bids at auction must be made available for leasing on a non-competitive basis to the first qualified applicant for a period of two years after the lease sale at which those parcels were initially offered. These non-competitive leases can be obtained, as explained below, after payment of the first year's rent and an administrative fee (30 U.S.C. 226(b)(1)(A); 43 CFR 3120.6). In aggregate, approximately 40 percent of the BLM-issued leases that are currently in force have been issued non-competitively (GAO–14–50 at 8). In FY 2014, approximately 10 percent of leases were issued non-competitively.

For all competitively-issued leases, the MLA requires a royalty ''at a rate of *not less than 12.5 percent* in amount or value of the production removed or sold from the lease'' (emphasis added) (30 U.S.C. 226(b)(1)(A); 30 U.S.C. 352 (applying that requirement to leases on acquired land)). Although the BLM is authorized under the MLA to specify a royalty rate higher than 12.5 percent for competitive leases, its existing regulations set a flat rate of 12.5 percent for such leases (43 CFR 3103.3–1(a)(1)).[3] For non-competitive leases, the royalty rate is fixed at a flat 12.5 percent of the value of the production by statute (30 U.S.C. 226(c) and 30 U.S.C. 352 (acquired lands)).

With this ANPR, the BLM seeks comments and suggestions on potential revisions to the royalty rate system that are consistent with the applicable statutory authorities (*e.g.,* the statutory floor of 12.5 percent). Consistent with existing requirements, any potential revisions to royalty rates, like those discussed below, would apply only to new leases obtained competitively; non-competitive leases would remain at the statutorily mandated 12.5 percent. Also, any potential revisions would not apply to leases issued under the Indian Mineral Leasing Act (tribal leases), 25 U.S.C. 396 (allotted leases), or the Indian Mineral Development Act. It should also be noted that any revisions to royalty rates would apply only to leases issued after the effective date of any final rule.

Revenue generated from developing public energy resources that belong to all Americans helps fund critical investments in communities across the United States and creates American jobs, fosters land and water conservation efforts, improves critical infrastructure, and supports education. For FY 2014, onshore Federal oil and gas leases produced about 148 million barrels of oil, 2.48 trillion cubic feet of natural gas, and 2.9 billion gallons of natural gas liquids, with a market value of almost $27 billion and generating royalties of almost $3.1 billion. Nearly half of these revenues are distributed to the States in which the leases are located.

The adequacy of the Department's oil and gas fiscal system has been the subject of many studies by GAO, the Interior Department's Office of the Inspector General (OIG), and other entities. The total government revenues as a share of total lease revenues is the revenue generated from taxes, fees, rental payments, bonus payments, and royalties. This revenue in aggregate is commonly referred to as the ''government take.'' GAO uses government take figures to compare various oil and gas fiscal systems, such as those used on State-managed lands and in certain foreign countries. The BLM's goal is to design an oil and gas fiscal system that both ensures that the United States' oil and gas resources are developed and managed in an environmentally-responsible way that meets our energy needs, while also ensuring that the American people receive a fair return on those resources (GAO–14–50 at 7).

In 2007 and 2008, the GAO released two reports focused on the adequacy of the United States' oil and gas fiscal system. The first report,[4] which compared oil and gas revenues received by the United States Government with the revenues that foreign governments receive from the development of public oil and gas resources in those countries, concluded that the United States Government receives one of the lowest percentages in government revenue from public oil and gas resource development in the world (GAO–07–676R at 2). The second report,[5] which focused on whether the Department received a fair return on the resources it managed, cited the ''lack of price flexibility in royalty rates'' and ''the inability to change fiscal terms on existing leases,'' in support of GAO's finding that the United States could be foregoing significant revenue from the production of Federal oil and gas resources (GAO–08–691 at 6). The report also faulted the Department for not having procedures in place to routinely evaluate the ranking of the Federal oil and gas fiscal system, or the industry rates of return on Federal leases versus other resource owners (GAO–08–691 at 6). As a result, GAO recommended that the U.S. Congress direct the Secretary to convene an independent panel to conduct a review of the Federal oil and gas fiscal system and establish procedures to periodically evaluate the system going forward. The U.S. Congress did not take any action on the GAO's recommendation; however, as explained below, the Department, including the BLM, undertook its own review in response to the GAO's findings.

In an effort to respond to the GAO's findings, the BLM, in coordination with the Bureau of Ocean Energy Management (BOEM), contracted for a comparative assessment of oil and gas fiscal systems on selected Department-managed Federal lands, State-managed lands, and in certain foreign countries (IHS CERA Study).[6] The Study identified four factors that are amenable to relative comparisons: government take, internal rate of return, profit-investment ratio, and progressivity. The Study also considered measures of revenue risk and fiscal system stability. In net, the IHS CERA Study found that as of the time of its report, the Federal Government's fiscal system and overall government take in aggregate were generally in the mainstream nationally and internationally. However, the report estimated a relatively wide range of government take, even within specific geographic regions, and the Study's authors acknowledged that government take varies with commodity prices, reserve size, reservoir characteristics, resource location and development costs, distance from infrastructure, water depth, and other factors. As a result, the IHS CERA Study's authors tended to favor a sliding-scale royalty system over a fixed-rate royalty due to its relative progressivity and ability to respond to changes in commodity market conditions.

In addition to the IHS CERA Study, the BLM also reviewed a separate study that was conducted by industry, independent of the BLM's efforts (Van Meurs Study (2011)).[7] The Van Meurs

113–291, Sec. 3022. The BLM has not yet implemented that authority.

[3] Before the FOOGLRA, the BLM issued leases with royalty rates at or above 12.5 percent. Leases reinstated after termination due to failure to pay annual rental are subject to a higher royalty rate (43 CFR 3103.3–1(a)(2) and (3)).

[4] Government Accountability Office (May 2007). *Oil and Gas Royalties: A Comparison of the Share of Revenue Received from Oil and Gas Production by the Federal Government and Other Resource Owners* (GAO–07–676R).

[5] Government Accountability Office (September 2008). *Oil and Gas Royalties: The Federal System for Collecting Oil and Gas Revenues Needs Comprehensive Reassessment, September 2008* (GAO–08–691).

[6] IHS CERA (October 2011). *Comparative Assessment of the Federal Oil and Gas Fiscal System.* Available at *http://www.blm.gov/wo/st/en/prog/energy/comparative_assessment.html.*

[7] PFC Energy, Van Meurs Corporation, and Rodgers Oil & Gas Consulting (2011). *World Rating of Oil and Gas Terms: Volume 1—Rating of North*

Study looked at a wide range of jurisdictions and regions across North America and provided a comparison of the oil and gas fiscal systems on Federal, State, and private lands throughout the United States and the provinces in Canada. At the time it was published, the Van Meurs Study suggested that in the United States: (1) Government take was generally lower on Federal lands than the lessor's ''take'' on State lands or private lands; (2) Government take was higher for gas than for oil; and (3) The internal rate of return on leases was lower for gas than for oil. The Report also made several recommendations to State and Federal Governments in the United States and Canada, such as the application of different fiscal terms to oil leases relative to gas leases based on the prevailing prices of oil and gas at the time the report was published. The continued growth of natural gas production in the United States since the report was published raises questions about its conclusions related to the intersection of specific prices and individual government fiscal terms.

As reflected by the findings in the reports discussed above, there are challenges and uncertainties involved in comparing the relative government take across regions or among nations. As a result, the BLM is seeking through this ANPR additional points of comparison for evaluating whether or not the BLM could achieve a better return through changes to its royalty rate regulations. One such point of comparison would be an evaluation of royalty rates charged by States on oil and gas activities on State lands. This comparison is important because while the Federal Government is a large player, it is only one of many mineral rights owners in the United States. As a result, the royalty rates charged by other significant mineral rights owners in the United States are relevant to any assessment of the adequacy of the Federal system.

For purposes of discussion and comparison, the Table below presents information about royalty rates charged by the States for production on State lands. The States listed below were selected because they have significant oil and gas production or there is significant production from Federal onshore oil and gas resources there. The information in the Table is current as of December 2014. It should be noted that these States receive all of the royalty from production on State lands. On Federal lands, under the MLA, before the marginal ''net receipts sharing'' deduction of 2 percent before distribution, the States receive 50 percent of the royalty from production under most Federal leases located within that State by way of permanent indefinite appropriation (except Alaska where the State's share is 90 percent) (*see* 30 U.S.C. 191(a)).[8] As thetable below shows, the royalty rates on production from leases on private or State landsvary, but are generally believed to be between 12.5 percent and 25 percent.

SUMMARY OF STATE & PRIVATE LAND ROYALTY RATES

Jurisdiction	Royalty rate	Comment
California (State lands)	Negotiated on a lease-by-lease basis, but generally not less than 16.67 percent.	The California State Lands Commission does not auction parcels. It negotiates lease terms, but it generally cannot issue a lease with a royalty rate below 16.67 percent, by statute. Lease terms are often based on neighboring leases.
Colorado (State lands)	16.67 percent	Information from the Colorado State Land Board Frequently Asked Questions.
Montana (State lands)	16.67 percent	Montana statutes (Mont. Code Ann. § 77–3–432) establishes a royalty of no less than 12.5 percent. Montana's rule (Sec. 36.25.210) sets the royalty rate at 16.67 percent, unless the lease sale notice announces a higher rate; the most recent sale, in December 2014, did not specify a higher rate.
New Mexico (State lands)	18.75 percent for development leases; 16.67 percent for discovery leases.	Information from the December 2014 lease sale notice.
North Dakota (State lands)	18.75 percent or 16.67 percent depending on the county.	Leases in Billings, Divide, Dunn, Golden Valley, McKenzie, Mountrail, and Williams counties carry an 18.75 percent royalty rate. Leases in other counties carry a 16.67 percent royalty rate. The statutory minimum royalty rate for oil is 12.5 percent. N.D. Cent. Code 15–05–10. Current Board of University and School Lands rules (§ 85–06–06–05), as amended in 2012, set the higher rates noted above.
Texas (State lands)	20 to 25 percent depending on the type of State land being leased.	By statute (Tex. Nat. Res. Code Ann. § 52.022), the School Land Board must set a royalty rate of at least 12.5 percent. The effective royalty rates are specified in the notice for bids. The royalty applies to all subsequent wells drilled on a lease, so long as the first well met the time specifications. The specific rate applied to new leases currently varies between 20 to 25 percent depending on the type of State land the lease is located on, with most categories subject to a 25 percent royalty rate.[9] New leases on University Lands are currently subject to 25 percent royalty rate.[10]
Utah (State lands)	12.5 percent or 16.67 percent	By regulation (Utah Admin. Code. R. 652–20–1000), oil and gas leases must have a royalty rate of at least 12.5 percent. The 16.67 percent royalty rate is specified in the October 2014 lease sale notice.

American Terms for Oil and Gas Wells with a Special Report on Shale Plays.

[8] After ''net receipts sharing'' deductions, the percentage of MLA lease revenues distributed to the states is 88.2 percent in Alaska and 49 percent in all other states. Remaining receipts are deposited in the Reclamation Fund and miscellaneous receipts in the U.S. Treasury.

[9] Texas General Land Office, Oil and Gas Lease Bid Application (Jan. 20, 2015), *available at http://www.glo.texas.gov/what-we-do/energy-and-minerals/_documents/sealed-bids/bid01-20-15/web-notice-01-15.pdf.*

[10] University Lands, The University of Texas System, Standard Oil and Gas Lease Agreement Form, *available at http://www.utlands.utsystem.edu/forms/pdfs/LeaseAgreement45.pdf?201410.*

SUMMARY OF STATE & PRIVATE LAND ROYALTY RATES—Continued

Jurisdiction	Royalty rate	Comment
Wyoming (State lands)	16.67 percent; 12.5 percent if the parcel was offered in a previous lease sale but did not receive a bid.	Information from the November 2014 lease sale notice. By statute (Wyo. Stat. Ann. § 36–6–101(c)), royalty rate must not be less than 5 percent of oil and gas produced and saved.
Private Lands	Generally 12.5 percent to 25 percent	Varies by contract.

In 2013, the GAO issued another report identifying specific actions for the Department to take to ensure that the Federal Government is receiving a fair return on the resources it manages for the American public.[11] The GAO acknowledged that actions had been taken in response to its prior recommendations (GAO–14–50 at 11), but remained concerned that the Department has not taken steps to change the onshore royalty rate regulations and had not established procedures for the periodic assessment of the Federal oil and gas fiscal system (GAO–14–50 at 23).

This ANPR directly addresses the GAO's first concern, because through it the BLM is seeking additional information to help it resolve some of the potentially contradictory inferences that can be drawn from the reports described above as it considers potential changes to its onshore royalty rate regulations. The BLM would be particularly interested in information that would help it assess the adequacy of existing rates. With respect to the periodic assessment of the onshore oil and gas fiscal system, the BLM has completed a formal assessment (see IHS CERA Study above) and the Department has taken steps to track market conditions. However, it should be noted that because existing regulations set a fixed royalty rate for new competitive leases, periodic assessments of the fiscal system are of limited utility unless those rules are amended. Because the BLM is considering potential changes that would provide flexibility in setting royalty rates, it poses some questions below on the scope, proper methodologies, and recommended frequency of fiscal system assessments.[12]

In addition to the statutory requirements, there are several general economic factors that should be considered in assessing potential changes to the current royalty rate. First, it should be noted that there would be positive revenue benefits to the Federal Government from adopting reasonable royalty rate increases.[13] In the near term, these benefits may be partially offset by a reduction in the demand for new Federal competitive oil and gas leases. Such demand may decrease to varying degrees depending on the magnitude of an increase in royalty rate and the extent to which operators absorb the added costs. Thus, the BLM is interested in receiving information about how the magnitude of a particular royalty rate change might impact the relative attractiveness of Federal leases compared to State and private leases.

The BLM acknowledges that current oil and gas prices are low, relative to the average price over the past decade; however, recognizing the historic variability of those prices, the BLM would be interested in information on the impacts of any royalty rate change at a range of oil and gas prices. Additionally, the BLM would be interested in information about the interplay between commodity prices and a royalty rate's impact on the relative attractiveness of Federal oil and gas leases.

It may be argued that potential production decreases resulting from higher royalty rates could result in environmental benefits on Federal lands, such as a reduction in the number of surface acres disturbed by drilling and its associated infrastructure. The BLM would be interested in receiving information related to these potential environmental benefits, particularly studies where those benefits are quantified—*e.g.,* to what extent might such benefits be realized? Or, would they be largely offset by drilling and production shifting to State or private lands?

The BLM is also seeking input on how changes to the royalty rate might affect the strategies employed by potential lessees for obtaining Federal onshore oil and gas leases. As explained above, a company can either obtain a parcel during a lease sale (resulting in a competitive lease) or purchase those parcels that were not leased at the sale after-the-fact on a first-come, first-serve basis (resulting in a non-competitive lease). Under the first scenario, the operator has to pay a bonus bid and would be subject to any changes to the royalty rate set under amended regulations. For the non-competitive leases, there would be no bonus bid and the royalty rate on the lease is set by statute at a fixed 12.5 percent.[14] Thus, there is a possibility that prospective lessees may adjust their behavior in response to royalty rate changes, either by bidding less for competitive leases or by trying to obtain more leases non-competitively. The BLM is interested in information about the extent to which such a shift might occur and, if so, how to mitigate the effects of any shift in bidding behavior. However, the current belief is that the most attractive parcels (*i.e.,* those where discovery and development prospects are strongest) will continue to be sold at auction, as there is an inherent risk to the potential lessee of lost opportunity in wagering that there will be no bids on such parcels. For more marginal parcels, prospective lessees may be more likely to take the risk that they can obtain them non-competitively after an auction; however, as a general matter, marginal parcels are also less likely to be developed.

What the foregoing illustrates from the BLM's perspective is that selecting a royalty rate involves a series of trade-offs that have both positive and negative consequences. The goal is to find the right balance between higher revenue collections, oil and gas production, and the relative attractiveness of leasing on Federal lands. According to the GAO, in the royalty rate context, that means finding a government take that ''would strike a balance between encouraging private companies to invest in the development of oil and gas resources on federal lands . . . while maintaining the public's interest in collecting the appropriate level of revenues from the sale of the public's resources'' (GAO–08–691 at 2).

[11] Government Accountability Office (December 2013). *Oil and Gas Resources: Actions Needed for the Interior to Better Ensure a Fair Return* (GAO–14–50).

[12] The BLM notes that rulemaking would not be required to establish procedures for the periodic assessment of the onshore oil and gas fiscal system.

[13] See Draft Reports prepared by Enegis, LLC, for the BLM (Contract No. L10PD03433)—*Benefit-Cost and Economic Impact Analysis of Raising the Onshore Royalty Rate Associated with New Federal Oil Leasing* (April and July 2011 versions).

[14] Parties acquiring a lease non-competitively must also pay an application fee that is indexed for inflation. The fee amount for FY 2015 is $405.

It should also be remembered that oil and gas companies consider a range of factors in deciding where to invest. In addition to government take, they look at the size and availability of the oil and gas resources and the costs associated with extracting those resources (*e.g.*, technological and labor costs) in a given area. They also look at compliance costs, commodity prices, and infrastructure limitations. For example, a company may decide to invest in the United States given its stability, proven resources, and market access, even if government take and certain other costs were higher relative to another country.

Oil and Gas Lease Annual Rental Payments

Under the MLA, as amended by FOOGLRA in 1987, prior to the commencement of production of oil or gas in paying quantities, lessees are required to pay annual rent of ''not less than $1.50 per acre per year for the first through fifth years of the lease and not less than $2 per acre per year for each year thereafter'' (30 U.S.C. 226(d)). Following the commencement of production, this rental requirement converts to a minimum royalty in lieu of rental. The minimum royalty is ''not less than the rental which otherwise would be required for that lease year . . .'' when production began in paying quantities (*Id.*; 43 CFR 3103.2–2(c)) (explaining that rental payments are not due on leases for which royalty or minimum royalty is being paid). The BLM's regulations implementing this requirement fix the rental rates for leases issued after December 22, 1987, at ''$1.50 per acre or fraction thereof for the first 5 years of the lease term and $2 per acre or fraction thereof for any subsequent year'' (43 CFR 3103.2–2(a)).

The BLM has not increased the rental rates since they were initially set in 1987, even though the MLA only sets a floor for the rates that must be charged by the BLM. The BLM anticipates updating its rental rate requirements and seeks comments on appropriate changes as discussed further below. The BLM would be particularly interested in information about the rental rates charged by States and private landowners for acreage leased, but not yet producing.

Minimum Acceptable Bid

In addition to requiring onshore oil and gas leases to first be offered competitively, the MLA, as amended by FOOGLRA, also requires the Secretary to accept ''the highest bid from a responsible qualified bidder which is *equal to or greater than the national minimum acceptable bid*, without evaluation of the value of the lands proposed for lease'' (30 U.S.C. 226(b)(1)(A)) (emphasis added). The MLA sets the minimum bid at $2 per acre for a period of two years from December 22, 1987 (30 U.S.C. 226(b)(1)(B)). Notably, the MLA specifically contemplates that the Secretary may, at the conclusion of the two-year period established by the statute, ''establish by regulation a higher national minimum acceptable bid for all leases based upon a finding that such action is necessary: (i) To enhance financial returns to the United States; and (ii) to promote more efficient management of oil and gas resources on Federal lands'' *Id.*[15] The Secretary (through the BLM) has not exercised this authority.[16]

The minimum acceptable bid is important because it establishes the starting bid at the BLM's oil and gas lease sale auctions. Ideally, the starting bid at any auction should be set at a level to ensure a fair financial return for U.S. taxpayers on parcels acquired by third parties competitively. The BLM's experience indicates that most parcels sell for well in excess of the current minimum acceptable bid, which may suggest the current minimum acceptable bid could be higher. Therefore, the BLM is considering amending its regulations to increase the minimum acceptable bid and seeks comments on appropriate changes as discussed further below. The BLM would be particularly interested in information about any minimum bid requirements imposed by States that offer oil and gas leases competitively.

Additionally, the BLM would also be interested in information about the potential impacts of any increase in the minimum acceptable bid amount. As explained above, the minimum acceptable bid sets the floor at which BLM will accept a bid for a parcel offered at a lease sale auction. If the BLM does not receive bids that are equal to or greater than the minimum bid for a parcel, then it does not lease the parcel at the competitive sale. Parcels that are not leased competitively are available, per the MLA, for lease non-competitively for a period of two years following the auction. Entities leasing such parcels non-competitively are required to pay an administrative fee and the first year's rent, but a minimum acceptable bid or other bonus bid is not required. As a result, the BLM has an interest in ensuring that the minimum acceptable bid is not set so high as to encourage parcels to be leased non-competitively. The BLM would be interested in receiving information about whether or how to adjust the minimum acceptable bid and whether the BLM should consider establishing a different annual rental rate for non-competitively leased parcels to compensate for not receiving a minimum bid when the BLM issues leases non-competitively.

Oil and Gas Lease Bonding

The MLA authorizes the Secretary to establish standards ''. . . as may be necessary to ensure that an adequate bond, surety, or other financial arrangement will be established prior to the commencement of surface-disturbing activities on any lease, to ensure the complete and timely reclamation of the lease tract, and the restoration of any lands or surface waters adversely affected by lease operations after the abandonment or cessation of oil and gas operations on the lease'' (30 U.S.C. 226(g)). Consistent with this statutory direction, the existing regulations at 43 CFR 3104.1 require that, prior to surface disturbing activities related to drilling operations, the lessee, sublessee, or operator submit a surety or personal bond.

The purpose of the bond is to ensure the ''complete and timely plugging of the well(s), reclamation of the lease area(s), and the restoration of any lands or surface waters adversely affected by lease operations after the abandonment or cessation of oil and gas operations'' (43 CFR 3104.1(a)). The regulations at 43 CFR 3104.2–3104.4 set forth four different bond types:

(1) *Lease/Individual Bonds*, which by regulation only provide coverage for one lease and must be in an amount of not less than $10,000;

(2) *Statewide Bonds*, which cover all leases and operations in one State and must be in an amount of not less than $25,000;

(3) *Nationwide Bonds*, which cover all leases and operations nationwide and by regulation must be in an amount of not less than $150,000; and

(4) *Unit Operator's Bonds*, which may be used in lieu of individual lease, statewide, or nationwide bonds for operations conducted on leases committed to an approved unit agreement. Existing regulations do not

[15] The MLA also requires that ''[n]inety days before the Secretary makes any change in the national minimum acceptable bid, the Secretary shall notify the Committee on Natural Resources of the United States House of Representatives and the Committee on Energy and Natural Resources of the United States Senate.'' 30 U.S.C. 226(b)(1)(B).

[16] If the BLM were to increase the minimum acceptable bid, it would also have to amend the regulations at 43 CFR 3120.5–2, which currently require the winning bidder to pay at the day of sale the minimum acceptable bid of $2 per acre, in addition to the first year's rent, and a processing fee.

set a minimum amount for these types of bonds, but rather specify that the amount will be set by the Authorized Officer. The BLM has not increased the minimum bond amounts provided in the existing regulations since 1960. As a result, those minimums do not reflect inflation and likely do not cover the costs associated with the reclamation and restoration of any individual oil and gas operation. The BLM anticipates updating its bonding requirements and seeks comments on appropriate changes as discussed further below.

Civil Penalty Assessment

In a recent report (No. CR–IS–BLM–0004–2014), the Department's OIG expressed concern about the BLM's existing policies and procedures to detect trespass in or drilling without approval on Federal onshore oil and gas leases. Among other things, the OIG expressed concern about the adequacy of the BLM's policies to deter such activities and recommended that the BLM pursue increased monetary fines. In response to these concerns and as explained below, the BLM is seeking input on removing or modifying the caps on civil penalty assessments currently imposed by its existing regulations.

The civil penalty provisions in section 109 of FOGRMA (30 U.S.C. 1719), provide authority for the BLM to assess civil penalties in connection with certain activities on Federal onshore oil and gas leasing and operations. Section 109(a) and (b) (30 U.S.C. 1719(a) and (b)) provide for assessment of civil penalties of up to $500 per violation per day for failure to comply with FOGRMA, any mineral leasing law, any rule or regulation thereunder, or the terms of any lease. Such penalties accrue only after the issuance of a notice of the violation and failure by the party receiving the notice to correct the violation within 20 days after issuance of the notice. Penalties run from the date of the notice. If corrective action is not taken within 40 days, the maximum daily penalty increases to up to $5,000 per violation per day, dating from the date of the notice. Existing regulations at 43 CFR 3163.2(b) impose a cap on the total civil penalty that can be assessed under sections 109(a) and (b) at a maximum of 60 days, which results in a maximum possible civil penalty assessment of $300,000.

Section 109(c)(2) of FOGRMA (30 U.S.C. 1719(c)(2)) provides for a civil penalty of up to $10,000 per violation per day (without a requirement for prior notice and opportunity to correct) for failure or refusal to permit lawful entry or inspection. Current BLM regulations at 43 CFR 3163.2(e) cap the total assessment under section 109(c)(2) at a maximum of 20 days, resulting in a maximum penalty of $200,000.

Finally, section 109(d)(1) and (2) of FOGRMA (30 U.S.C. 1719(d)(1) and (2)), provide for a civil penalty of up to $25,000 per day (again without a requirement for prior notice and opportunity to correct) for knowingly or willfully preparing or submitting false, inaccurate, or misleading reports or information (subsection (d)(1)) or for knowingly or willfully taking, removing, or diverting oil or gas from any lease site without valid legal authority (subsection (d)(2)). Current BLM rules cap this penalty assessment at 20 days, or a maximum of $500,000 (43 CFR 3163.2(f)).

If a lessee or designated operator of a Federal onshore lease drills a well without an approved application for permit to drill (APD), the lessee or operator is liable for civil penalties under section 109(a) and (b) after notice and failure to timely correct. In such circumstances, the corrective action would be to obtain approval of an APD. The maximum penalty under such circumstances is $300,000. A person who knowingly or willfully drills a well into leased Federal land when that person is not a lessee or operator of the Federal lease is liable for civil penalties under section 109(d)(2), which are subject to a maximum penalty of $500,000. The OIG has questioned whether these penalty levels, which were established in the mid-1980s, provide an adequate deterrence given the current costs for completing a well in places like North Dakota, which the OIG reported as ranging between $8 to $12 million dollars.[17] The BLM anticipates updating its civil penalty regulations and seeks comments on appropriate changes as discussed further below.

III. Description of Information Requested

Onshore Royalty Rates and Periodic Assessments of the Onshore Fiscal System

The BLM is interested in receiving feedback on the following questions related to potential revisions to the royalty rate regulations governing competitively-issued onshore oil and gas leases:

1. The various reports and assessments of the Federal oil and gas fiscal system that the BLM has received, prepared, or reviewed, create potentially inconsistent inferences as to the adequacy existing royalty rates. What information should the BLM consider that would help it resolve those inconsistencies?

2. In evaluating whether or not existing royalty rates are providing a fair return to the public for leased oil and gas resources, what should the BLM consider, and on what factors should the BLM place the most weight?

a. Given the uncertainties associated with comparing current information on government take among countries and at different commodity prices, should the BLM primarily rely on comparisons to State and private land royalty rates?

b. To what extent should the BLM factor in the effects on production in assessing the appropriateness of applying a given royalty rate?

3. Should the BLM consider other factors in determining what royalty level might provide a fair return, such as life cycle costs, externalities, or the social costs associated with the extraction and use of the oil and gas resources? If the BLM should consider such factors, please explain how it should do so. The BLM currently offers all new competitive Federal oil and gas leases at a fixed royalty rate of 12.5 percent. Should the BLM:

a. Increase the royalty rate on oil and gas production above 12.5 percent to a different fixed royalty rate? If so, what should that rate be? For example, should the rate be increased to 18.75 percent consistent with the rate set for recent offshore lease sales? If not, why not?

b. Consider a sliding-scale royalty-rate structure based on an established index of oil and gas prices during a given period of time, as suggested by GAO? If so, how many price tiers would be optimal to balance administrative complexity with the opportunity to distinguish between meaningful price swings? What price thresholds would be appropriate for each tier? Should the thresholds be fixed (in real dollar terms), or should they float relative to a published index?

4. Whether the BLM keeps royalty rates fixed or adopts a sliding-scale rate structure, should it:

a. Maintain a national or uniform rate or rate schedule for all new competitive leases?

[17] Trespass actions involving unleased parcels are subject to the regulations at 43 CFR 9239.5–2, which provide as follows:

For oil trespass in a State where there is no State law governing such trespass, the measure of damages will be as follows:

(a) *Innocent trespass.* Value of oil taken, less amount of expense incurred in taking the same.

(b) *Willful trespass.* Value of the oil taken without credit or deduction for the expense incurred by the wrongdoers in getting it. *Mason* v. *United States* (273 Fed. 135).

b. Establish potentially different royalty rates or rate schedules for new leases by region, State, lease sale, formation, resource type (*e.g.*, crude oil, crude oil from tight formations, natural gas, and natural gas from shale formations) or other category? In each case, how should the BLM determine what the royalty rates should be? For instance, if by region, how would the various rates for different regions be determined?

5. What other royalty rate structures (not listed previously) should the BLM consider?

6. Instead of amending the regulations to set a new fixed rate or impose an adjustable rate structure as part of a new formal regulation, should the BLM revise its regulations so that the Secretary (through the BLM) has the authority to set the royalty rate terms for new leases outside of a formal rulemaking process?

a. One option would be to set the rate terms in individual Notice of Lease Sale documents in a manner similar to the existing offshore authorities, but this raises other potential complications (*e.g.*, loss of transparency, greater challenges in revenue tracking and estimation) given the frequency and processes used for BLM lease sales compared to offshore sales. If the terms are set on a lease sale-by-sale basis, what market conditions or factors should be considered in setting the royalty rates for a particular sale? What weight should be given to individual factors?

b. Is there another approach that should be considered to strike a balance between the competing objectives of flexibility, transparency, and simplicity? Should the BLM (or the Secretary) maintain a set national rate schedule that would be updated periodically on a fixed schedule (*e.g.*, annually) or as circumstances warrant (*e.g.*, when certain price triggers are hit)?

7. How should the BLM undertake assessments of the oil and gas fiscal system?

a. What methodologies, information, and resources should it consider as part of such assessments? In responding, please consider whether any factor should be given more weight than another.

b. How often should such assessments occur? Every year? Every five years? Every 10 years? As necessary based on some trigger? If you recommend a trigger-based approach, please identify the trigger.

Annual Rental Payments

The BLM is interested in receiving feedback on the following questions related to potential changes to its annual rental payment requirements:

1. Should the BLM increase the annual rental payments set forth in 43 CFR subpart 3103? If so, by how much? If not, why are current payment levels sufficient to ensure the diligent development of an oil and gas lease?

2. If the BLM were to increase annual rental payments, what factors should it consider in proposing an increase?

a. Should rental payments simply be adjusted to reflect inflation?

b. Are there other factors the BLM should consider?

3. If the BLM were to increase the annual rental payments:

a. How should the BLM implement those changes—*e.g.*, should it consider a phase-in?

b. Is there another way to have annual rentals escalate over time besides the current category of years 1 through 5 and then a higher rental for years 6–10?

4. Are there any other changes or refinements that the BLM should consider to its current annual rental payment requirements?

5. What are the comparable State practices with respect to annual rental payments?

Minimum Acceptable Bid

The BLM is interested in receiving feedback on the following questions related to potential changes to its regulations to increase the minimum acceptable bid required for oil and gas leases offered competitively:

1. Should the BLM increase the current minimum acceptable bid of $2 per acre? If so, by how much?

2. If the BLM were to increase the minimum bid:

a. What factors should it consider in proposing an increase? For any factors, please explain how they relate to: (1) Enhancing financial returns to the United States; and (2) promoting more efficient management of oil and gas resources on Federal lands.

b. What are the potential impacts of any such increase? Does it vary by the magnitude of the increase?

c. Should the BLM amend its regulations to give the Authorized Officer discretion to adjust the minimum bid based upon market conditions?

d. Should the BLM raise the rental rates for leases acquired non-competitively to compensate for not receiving even minimum bids for such leases? If so, what would a reasonable rental rate be for non-competitively issued leases?

3. What are the comparable State practices with respect to minimum bids for leases acquired competitively?

Bonding

The BLM is interested in receiving feedback on the following questions related to potential changes to its bonding requirements:

1. Should the BLM increase the minimum bond amounts set forth in 43 CFR subpart 3104? If so, by how much? If not, why are current bonding levels sufficient?

2. If the BLM were to increase minimum bonds amounts, what factors should it consider?

a. Should bond minimums simply be adjusted to reflect inflation?

b. Should they be adjusted to reflect an estimate of best case, average, or worst case reclamation and restoration costs? In connection with this question, the BLM would be interested in receiving estimates of such reclamation and restoration costs.

c. Are there other factors the BLM should consider? Are there best practices at the State level that the BLM should consider adopting?

3. If the BLM were to increase the minimum bond amounts:

a. Should it provide a way for those amounts to automatically rise, such as if they were to track inflation?

b. How should it implement those changes—*e.g.*, should it consider a phase-in?

c. Existing authorities permit the BLM to adjust bond amounts up and down, but no lower than the minimum amount. In light of those authorities, if the BLM were to increase bond minimums, should it consider provisions to allow a party to request, on a case-by-case basis, a decrease in its bond amount to below the minimum if, for example, the BLM were to determine that the potential liabilities on a particular lease are less than the applicable minimum bond amounts? Please identify any standards the BLM should use to determine whether to approve such a request.

4. Are there any other activities for which the BLM should consider requiring a bond?

a. In the past the BLM has considered adding a new bond for inactive wells; should the BLM revisit such a proposal?

b. Similarly should the BLM consider adding a royalty bond to address issues related to unpaid royalties? Adding a royalty bond would mean that funds available under the other, general bonds would not need to be used for anything other than reclamation. Currently, the bonds can address reclamation and royalty issues, among other things.

c. For any new bond types that you think the BLM should consider, please explain how the bond amounts should be set and what the scope of coverage should be.

5. Are there any other changes or refinements that the BLM should consider to its current oil and gas bonding, surety and financial arrangement requirements?

Civil Penalty Assessments

The BLM is interested in receiving feedback on the following questions related to changes to the current caps on civil penalty assessments:

1. Should the current regulatory caps on the amount of civil penalties that may be assessed be removed?

2. If regulatory caps on the maximum amount of civil penalty assessments should remain, at what level should they be set to adequately deter improper action—in particular, drilling without an approved APD or drilling into Federal leases in knowing or willful trespass?

Non-Penalty Assessments and Trespass

1. In addition to the caps on civil penalties set forth at 43 CFR 3163.2, should the BLM consider revising any of the assessments set forth in 43 CFR 3163.1? If so, what changes should be made and on what basis?

2. Should the BLM consider revising its oil trespass regulations set forth at 43 CFR 9239.5–2? If so, what changes should be made and on what basis?

In addition to the specific information requests identified above, the BLM is also interested in receiving any other comments you may have regarding royalty rates, annual rental payments, minimum acceptable bids, bonding requirements, or the current regulatory caps on civil penalty assessments for BLM-managed oil and gas leases.

Janice M. Schneider,

Assistant Secretary, Land and Minerals Management.

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 660

[Docket No. 150305219–5219–01]

RIN 0648–BE78

Fisheries Off West Coast States; Highly Migratory Species Fisheries

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Proposed rule; request for comments.

SUMMARY: The National Marine Fisheries Service (NMFS) is proposing to modify the existing Pacific bluefin tuna (PBF) *Thunnus orientalis* recreational daily bag limit in the Exclusive Economic Zone (EEZ) off California, and to establish filleting-at-sea requirements for any tuna species in the U.S. EEZ south of Point Conception, Santa Barbara County, under the Magnuson-Stevens Fishery Conservation and Management Act (MSA). This action is intended to conserve PBF, and is based on a recommendation of the Pacific Fishery Management Council (Council).

DATES: Comments on the proposed rule must be submitted in writing by May 6, 2015.

ADDRESSES: You may submit comments on this document, identified by NOAA–NMFS–2015–0029, by any of the following methods:

• *Electronic Submission:* Submit all electronic public comments via the Federal e-Rulemaking Portal. Go to *http://www.regulations.gov/#!docketDetail;D=NOAA-NMFS-2015-0029*, click the ''Comment Now!'' icon, complete the required fields, and enter or attach your comments.

• *Mail:* Submit written comments to Craig Heberer, NMFS West Coast Region Long Beach Office, 501 W. Ocean Blvd., Suite 4200, Long Beach, CA 90802. Include the identifier ''NOAA–NMFS–2015–0029'' in the comments.

Instructions: Comments must be submitted by one of the above methods to ensure they are received, documented, and considered by NMFS. Comments sent by any other method, to any other address or individual, or received after the end of the comment period, may not be considered. All comments received are a part of the public record and will generally be posted for public viewing on *www.regulations.gov* without change. All personal identifying information (*e.g.*, name, address, etc.) submitted voluntarily by the sender will be publicly accessible. Do not submit confidential business information, or otherwise sensitive or protected information. NMFS will accept anonymous comments (enter ''N/A'' in the required fields if you wish to remain anonymous).

Copies of the draft Regulatory Impact Review (RIR) and other supporting documents are available via the Federal eRulemaking Portal: *http://www.regulations.gov*, docket NOAA–NMFS–2015–0029, or contact the Regional Administrator, William W. Stelle, Jr., NMFS West Coast Regional Office, 7600 Sand Point Way, NE., Bldg 1, Seattle, WA. 98115–0070, or *RegionalAdministrator.WCRHMS@noaa.gov*.

FOR FURTHER INFORMATION CONTACT: Craig Heberer, NMFS, 760–431–9440, ext. 303.

SUPPLEMENTARY INFORMATION: On April 7, 2004, NMFS published a final rule (69 FR 18444) to implement the Fishery Management Plan for U.S. West Coast Fisheries for Highly Migratory Species (HMS FMP) that included annual specification guidelines at 50 CFR 660.709. These guidelines establish a process for the Council to take final action at its regularly-scheduled November meeting on any necessary harvest guideline, quota, or other management measure and recommend any such action to NMFS. At their November 2014, meeting, the Council adopted a recommendation (*http://www.pcouncil.org/wp-content/uploads/1114decisions.pdf*) to modify the existing daily bag limit regulations at 50 CFR 660.721 for sport caught PBF harvested in the EEZ off the coast of California and to promulgate at-sea fillet regulations applicable south of Santa Barbara as routine management measures for the 2014–2015 biennial management cycle. The Council's recommendation and NMFS' proposed rulemaking are intended to reduce fishing mortality and aid in rebuilding the PBF stock, which is overfished and subject to overfishing (78 FR 41033, July 9, 2013; 80 FR 12621, March 9, 2015) and to satisfy the United States' obligation to reduce catches of PBF by sportfishing vessels in accordance with Inter-American Tropical Tuna Commission (IATTC) Resolution C–14–06. (*http://www.iattc.org/PDFFiles2/Resolutions/C-14-06-Conservation-of-bluefin-2015-2016.pdf*).

Resolution C–14–06 requires that ''in 2015, all IATTC Members and Cooperating non-Members (CPCs) must take meaningful measures to reduce catches of PBF by sportfishing vessels operating under their jurisdiction to levels comparable to the levels of reduction applied under this resolution to the EPO commercial fisheries until such time that the stock is rebuilt.'' The proposed daily bag limit of two fish per day being considered under this proposed rule would reduce the U.S. recreational harvest of PBF by approximately 30 percent, which is consistent with the IATTC scientific staff's conservation recommendation for a 20–45 percent PBF harvest reduction and meets the requirements of IATTC Resolution C–14–06. The filleting-at-sea