Federal Accounting Standards Advisory Board

Accounting for

Federal Oil and Gas Resources

Proposed Statement of Federal Financial Accounting Standards

Exposure Draft

Written comments are requested by September 21, 2007

May 21, 2007

THE FEDERAL ACCOUNTING STANDARDS ADVISORY BOARD

The Federal Accounting Standards Advisory Board (FASAB or "the Board") was established by the Secretary of the Treasury, the Director of the Office of Management and Budget (OMB), and the Comptroller General in October 1990. It is responsible for promulgating accounting standards for the United States Government. These standards are recognized as generally accepted accounting principles (GAAP) for the Federal Government.

An accounting standard is typically formulated initially as a proposal after considering the financial and budgetary information needs of citizens (including the news media, state and local legislators, analysts from private firms, academe, and elsewhere), Congress, Federal executives, Federal program managers, and other users of Federal financial information. The proposed standard is published in an Exposure Draft for public comment. In some cases, a discussion memorandum, invitation for comment, or preliminary views document may be published before an exposure draft is published on a specific topic. A public hearing is sometimes held to receive oral comments in addition to written comments. The Board considers comments and decides whether to adopt the proposed standard with or without modification. After review by the three officials who sponsor FASAB, the Board publishes adopted standards in a Statement of Federal Financial Accounting Standards. The Board follows a similar process for Statements of Federal Financial Accounting Concepts, which guide the Board in developing accounting standards and formulating the framework for Federal accounting and reporting.

Additional background information is available from the FASAB:

- "Memorandum of Understanding among the General Accounting Office, the Department of the Treasury, and the Office of Management and Budget, on Federal Government Accounting Standards and a Federal Accounting Standards Advisory Board."

- "Mission Statement: Federal Accounting Standards Advisory Board"

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Federal Accounting Standards Advisory Board

May 21, 2007

TO: ALL WHO USE, PREPARE, AND AUDIT FEDERAL FINANCIAL INFORMATION

The Federal Accounting Standards Advisory Board (FASAB) is requesting comments on the exposure draft (ED) of a proposed Statement of Federal Financial Accounting Standards entitled *Accounting for Federal Oil and Gas Resources*. Currently, there are no specific accounting standards for Federal oil and gas resources. This ED contains proposed standards that would address the recognition of an asset and a related liability, revenue and expense, gains and losses, and rights to future royalty streams identified for sale, as well as implementation guidance for the Federal government's royalty share of proved oil and lease condensate, natural gas plant liquids (NGPLs), and gas reserves. It would also address disclosure requirements and required supplementary information (RSI) for other Federal oil and gas resources not classified as proved reserves. The standards proposed in this ED would take effect for accounting periods beginning after September 30, 2009.

Specific questions for your consideration begin on page vii but you are welcome to comment on any aspect of this proposal. Your responses to the questions would be more helpful to the Board if you explain the reasons for your position and any alternative you propose. It should be noted that question two (Q2) deals with an alternative view to the measurement approach proposed to value the asset. (See alternative view beginning at paragraph A119.) Responses are requested by September 21, 2007. All comments received by the FASAB are considered public information. Those comments may be posted to the FASAB's website and will be included in the project's public record.

We have experienced delays in mail delivery due to increased screening procedures. Therefore, please provide your comments in electronic form. Responses in electronic form should be sent by e-mail to comesw@fasab.gov. If you are unable to provide electronic delivery, we urge you to fax the comments to (202) 512-7366. Please follow up by mailing your comments to:

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The Board's rules of procedure provide that it may hold one or more public hearings on any exposure draft. No hearing has yet been scheduled for this exposure draft. Notice of the date and location of any public hearing on this document will be published in the Federal Register and in the FASAB's newsletter.

Tom L. Allen
Chairman

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EXECUTIVE SUMMARY

What is the Board proposing?

This exposure draft (ED) proposes accounting standards for Federal oil and gas resources.[1] The proposed standards would result in the recognition of an asset and a related liability. The asset would be referred to as "estimated petroleum royalties." The asset's value would be the royalty share of the Federal oil and gas resources classified as "proved reserves."[2] The asset's value would be calculated by multiplying the estimated quantity of proved oil and lease condensate,[3] natural gas plant liquids (NGPLs),[4] and gas reserves by the effective average royalty rate for each quantity and by the average per unit price for each quantity. An alternative approach to valuing estimated petroleum royalties is fair value. One Board member believes that fair value is feasible and preferable (See alternative view beginning at paragraph A119). The Board member believes that fair value could be derived from market transactions or discounted cash flows.

The related liability would be for the royalty share of the Federal oil and gas resources classified as "proved reserves" designated to be distributed to others, i.e., state governments and – at the component entity level – other federal agencies and the general fund of the U.S. Treasury. The liability would be calculated by assessing the total estimated petroleum royalties to be distributed to others.

When oil and gas resources are extracted and royalties are earned, revenue and a depletion expense equal to the earned revenue would be recognized by the Federal government. When revenue collections are distributed a reduction in the liability for revenue distributions to others would be recognized. Gains and losses due to changes in the estimated quantity of proved oil and lease condensate, NGPLs, and gas reserves,[5] the effective regional average royalty rates, and the average per unit prices would be recognized based on an annual valuation of the asset with an associated adjustment to the liability for revenue distributions to others. In addition, when rights to a future royalty stream are identified to be sold, the value of the related rights would be disclosed.

[1] Federal Oil and Gas Resources: Oil and gas resources over which the Federal government may exercise sovereign rights with respect to exploration and exploitation and from which the Federal government has the authority to derive revenues for its use. Federal oil and gas resources do not include resources over which the Federal government acts as a fiduciary for the benefit of a nonfederal party.
[2] A portion of the production value of proved oil and gas reserves are due the Federal government from the lessee in accordance with the royalty rate contained in the lease agreement.
[3] Lease condensate: A mixture consisting primarily of pentanes and heavier hydrocarbons which is recovered as a liquid from natural gas in lease separation facilities.
[4] Natural gas plant liquids (NGPLs): Those hydrocarbons in natural gas that are separated as liquids at natural gas processing plants, fractionating and cycling plants, and, in some instances, field facilities. Lease condensate is excluded. Products obtained include ethane; liquefied petroleum gases (propane, butanes, propane-butane mixtures, ethane-propane mixtures); isopentane; and other small quantities of finished products, such as motor gasoline, special naphthas, jet fuel, kerosene, and distillate fuel oil.
[5] Changes in the estimated quantity of proved oil and lease condensate, NGPLs, and gas reserves result from changing economic conditions, technological advancements, improved information, new leases, and other changes.

Transition to these proposed standards would require that the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves be recognized as an asset and a related liability be established as of the beginning of the reporting period in which the standards become effective. This net effect of recognizing the asset and establishing the related liability at the beginning of the reporting period would be a change in accounting principle that increases the entity's net position. Additional information about Federal oil and gas resources not classified as proved reserves would be disclosed in notes to the financial statements or reported as required supplementary information (RSI).

The proposed standards would be effective for periods beginning after September 30, 2009, with early implementation permitted.

Why is the Board making this proposal?

The Board issued accounting standards applicable to land in 1995 and 1996 but elected to specifically exclude natural resources from the scope of those standards. Extensive Federal oil and gas resources exist on public lands throughout the country and on the Outer Continental Shelf (OCS). Currently, federal financial reporting does not provide information about the quantity or value of these assets. In addition, royalty revenues are recognized but expenses are not recognized for the asset exchanged to produce those revenues. The Board is proposing standards that would fill this void in financial accounting standards and result in information that contributes to meeting federal financial reporting objectives.

Challenges regarding accounting for these assets include obtaining reliable estimates of the quantity of resources, determining a relevant value for the assets, and ensuring that the cost of doing so does not exceed the benefits. This proposal would make use of information currently available – estimates of proved reserves currently provided to the Energy Information Administration (EIA) on an annual basis, average regional prices and average regional royalty rates. This proposal would not result in new assessments of the quantity of reserves or require modeling of expected cash flows to be derived from current leases. This proposal would result in implementation of the existing exchange revenue accounting model for royalty revenues earned during each period. The Board believes that this proposal would fill a substantial void in the accounting standards in the most practical manner available.

How does this proposal improve Federal financial reporting?

Federal oil and gas resources represent Federal assets. Accounting for and reporting information about these assets would enhance:

a. Accountability for and stewardship over assets of the Federal government.
b. Consistency and understandability in accounting for assets of the Federal government.
c. Relevance, consistency, and comparability of information regarding revenue of the Federal government.

Recognizing the Federal government's royalty share of proved reserves as an asset with a related liability on the balance sheet would provide transparency regarding the value and changes in value of these significant assets. Federal financial reports would be more relevant, consistent, and complete. Additional disclosures about Federal oil and gas resources would provide comprehensive information about Federal assets, reveal changes in the quantity and status of oil and gas resources, and make quantity information more accessible to users of financial information.

Bonus bid, rent, and royalty collections – currently treated as nonexchange revenue due to the absence of cost information – would be accounted for and reported in accordance with exchange revenue standards. This treatment would improve the comparability of revenue information.

How does this proposal contribute to meeting the Federal financial reporting objectives?

Based on the objectives outlined in Statement of Federal Financial Accounting Concepts Statement (SFFAC) 1, *Objectives of Federal Financial Reporting*, the operating performance and stewardship objectives were identified as most important for natural resources reporting.

With respect to meeting the operating performance reporting objective, the proposed standard would provide information useful in evaluating the reporting entity's management of assets relating to oil and gas resources. The proposal would result in disclosure of the quantity of proved reserves at the end of each period, the average sales value of resources extracted during the period, the effective average royalty rate realized during the period and the end of period value of all estimated petroleum royalties. This information would allow financial report users to monitor changes in royalty rates and estimated reserve quantities; providing an indicator of how well the government's proved reserves were managed. In addition, the value of the estimated petroleum royalties at the end of each period would facilitate consideration of the potential cash flows from existing leases.

Operating Performance Objective
Federal financial reporting should assist report users in evaluating the service efforts, costs, and accomplishments of the reporting entity; the manner in which these efforts and accomplishments have been financed; and the management of the entity's assets and liabilities. Federal financial reporting should provide information that helps the reader to determine • the costs of providing specific programs and activities and the composition of, and changes in, these costs; • the efforts and accomplishments associated with federal programs and the changes over time and in relation to costs; and • the efficiency and effectiveness of the government's management of its assets and liabilities. Source: SFFAC 1

Currently, royalties from oil and gas leases are displayed on the Statement of Changes in Net Position with non-exchange revenue rather than on the Statement of Net Cost with other exchange revenue. Presentation of revenues arising from oil and gas leasing activities as exchange revenue would assist users in understanding how the government's efforts and accomplishments were financed. The current practice of combining revenues derived from the sale of assets with revenues derived from taxation or other non-exchange sources may obscure the fact that the gains were obtained through the exchange of resources—proved reserves for a future stream of royalty payments.

With respect to meeting the stewardship reporting objective, the proposed standard would provide information useful in assessing whether Federal government operations have contributed to the nation's current and future well-being. Recognition of estimated petroleum royalties as an asset would make available the value of an asset that generates cash to finance government operations over time. This would inform users about the financial position of the government and whether it was improving or deteriorating over time. Information about potential oil and gas production and changes in potential production over time would allow users to consider how government operations and economic conditions have impacted the availability of oil and gas resources to future generations.

Stewardship Objective
Federal financial reporting should assist report users in assessing the impact on the country of the government's operations and investments for the period and how, as a result, the government's and the nation's financial condition has changed and may change in the future. Federal financial reporting should provide information that helps the reader to determine whether • the government's financial position improved or deteriorated over the period, • future budgetary resources will likely be sufficient to sustain public services and to meet obligations as they come due, and • government operations have contributed to the nation's current and future well-being. Source: SFFAC 1

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REQUEST FOR COMMENTS

The FASAB encourages you to become familiar with all proposals in this proposed Statement before responding to the questions in this section. The paragraphs cited in a question are particularly relevant to that issue, but other portions of the document also may enhance your understanding of the question. The Board also would welcome your comments on other aspects of the proposals in this proposed Statement.

The Board believes that this proposal would improve Federal financial reporting and contribute to meeting the Federal financial reporting objectives. The Board has considered the perceived costs associated with this proposal. In responding, please consider the expected benefits and perceived costs and communicate any concerns that you may have in regard to implementing this proposal.

The Board believes that pilot tests are beneficial and can assist the Board in resolving complex issues not found in existing standards. This proposal introduces a new valuation technique. In addition, one member has recommended a different valuation technique -- fair value. The Department of the Interior will conduct a pilot test of the proposal during the comment period. The results of the pilot test will assist the Board in evaluating alternative methods and developing a final standard.

Because the proposals may be modified before a final Statement is issued, it is important that you comment on proposals that you agree with as well as any that you disagree with. Comments that include the reasons for your views will be especially appreciated.

The questions in this section are available in a Word file for your use at www.fasab.gov/exposure.html. Your responses to the Request for Comments questions should be sent by e-mail to comesw@fasab.gov. If you are unable to respond electronically, please fax your responses to (202) 512-7366 and follow up by mailing your responses to:

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All responses are requested by September 21, 2007.

Q1. The proposed standards would provide for recognition of the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves. These reserves are subcomponents of the total oil and gas resources of the Federal government. Please see page 20 for an illustration of Federal oil and gas resource components and subcomponents.

The Board's proposal for quantifying the Federal government's royalty share of proved reserves is to use a single best estimate of recovering reserves based on known geological, engineering, and economic data. This approach is known in the oil and gas industry as the deterministic method. This method would exclude reserves other than proved reserves. In contrast, a probabilistic method of estimation uses the known geological, engineering, and economic data to generate a range of estimates and their associated probabilities of recovering reserves. It would include more than proved reserves. See paragraphs A73 through A78 for additional information regarding the deterministic and probabilistic methods for measuring and reporting proved oil and lease condensate, NGPLs, and gas reserves.

Determination of Quantity:

a. Which of the following two options would you prefer?
    i. Capitalize estimated petroleum royalties from the proved reserves based on the deterministic method as proposed in the ED.
    ii. Capitalize estimated petroleum royalties from proved reserves, probable reserves, and possible reserves based on the methodology proposed in the alternative view. See the alternative view beginning at paragraph A119.
b. Please explain the reasons for your preference.
c. If you prefer a different basis for determining the quantity of reserves, please explain the alternative you propose and why you prefer it.

Q2. The Board proposes to value the Federal government's royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date. See paragraphs 16 through 19 and 37. Also, see paragraphs A48 through A53 for a discussion of measurement attributes that were considered and paragraphs A79 through A113 for a discussion of the valuation approach proposed. An alternative approach to valuing estimated petroleum royalties is fair value. Fair value is the price that would be received for an asset or paid to transfer a liability in a transaction between market participants at the measurement date. One Board member believes that fair value is feasible and preferable. See the alternative view beginning at paragraph A119. The Board member believes that fair value could be derived from market transactions or discounted cash flows. The view of the majority of the Board members is that fair value would not produce a more reliable valuation than the valuation method proposed in this ED due to the challenges in adopting a fair value method.

Determination of Value:

a. Which method do you believe is most appropriate for valuing estimated petroleum royalties?
    i. Value the royalty share of proved reserves based on average regional prices and effective average regional royalty rates experienced during the 12 months preceding the balance sheet date.
    ii. Value estimated petroleum royalties using the alternative view fair value method.
b. Please explain the reasons for your preference.
c. If you prefer a different method for valuing estimated petroleum royalties, please describe the method you propose and why you prefer it.

Q3. Some Board members believe that the amount of information proposed to be disclosed in the notes and provided as RSI is excessive. See the disclosure and RSI requirements presented in paragraphs 30 through 34 and Appendix D for a complete review of all proposed disclosures and RSI.

a. Do you believe that each item of information, whether disclosed in the notes or provided as RSI, is necessary to meet reporting objectives and is cost-beneficial to provide? Particularly, consider Table 1 on pages 68 and 69 and Table 2 on pages 70 and 71. It would be helpful if specific information that respondents believe could be deleted or added were identified.
b. How would each item of information be used for decision-making or assessing the financial position of the Federal government?
c. Please explain the reasons for your position and any alternative you propose.

Q4. The proposed standards would require that an estimated value for royalty relief be reported as RSI. The Minerals Management Service (MMS) has a variety of royalty relief programs. Royalty relief is the reduction, modification, or elimination of any royalty to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. See paragraphs A90 through A94 for additional information regarding MMS royalty relief programs.

a. Do you believe that a monetary value for royalty relief should be reported as RSI? Please explain the reasons for your position.
b. Do you believe the quantity of production for which relief was granted during the reporting period should be reported as RSI? Please explain the reasons for your position.

Q5. Statement of Federal Financial Accounting Standards (SFFAS) 7, *Accounting for Revenue and Other Financing Sources* (as amended), requires that agencies report on assets held in a fiduciary capacity.[6] The Board recently issued SFFAS 31, *Accounting for Fiduciary Activities*. SFFAS 31 will supersede SFFAS 7 with respect to fiduciary activities but continues the requirement to report on assets held in a fiduciary capacity. The Department of Interior (DOI) manages oil and gas resources on behalf of individual Indians and Indian tribes. This proposed standard – because it classifies oil and gas resources as assets – would result in additional information being disclosed for oil and gas assets managed in a fiduciary capacity. Note, however, that fiduciary reporting does not extend to inclusion of the additional disclosures or RSI that are proposed in this document for Federal oil and gas resources. Thus, with respect to fiduciary activities, only disclosure of the assets, liabilities, and related inflows and outflows would result from this proposal.

Some Board members have expressed concern that the costs may exceed the benefits of disclosing fiduciary assets and liabilities measured in conformance with this proposed standard. Since this proposal may significantly increase the fiduciary assets disclosed, we are requesting input on the cost-benefit of the requirement with respect to fiduciary activities. See paragraph 34.

[6] SFFAS 7, paragraphs 83 to 87.

a. Do you believe it is cost-beneficial to require disclosure of the value of estimated fiduciary petroleum royalty assets, liabilities, and related inflows and outflows? Please explain the basis for your beliefs.

Q6. The proposed standards would require the component entity to provide extensive disclosures and RSI. However, the Consolidated Financial Report (CFR) of the United States government would be required to include limited disclosures and no supplementary information. See paragraphs 31 through 33. These divergent reporting requirements are consistent with SFFAC 4, *Intended Audience and Qualitative Characteristics for the Consolidated Financial Report of the United States Government*. SFFAC 4 provides that the CFR should be highly aggregated and offer references to other reports.

a. Do you believe that the CFR disclosure requirements should be limited as proposed? Please explain the basis for your beliefs.

Q7. This proposal includes accommodations intended to reduce the cost or burden of implementation. These accommodations are identified below along with the alternatives considered and rejected by a majority of the members. Please comment on any accommodation that you believe is not appropriate or that you believe does not sufficiently reduce the cost or burden of the proposal.

a. Asset recognition is limited to proved reserves. However, the Board believes that other than proved reserves (e.g., unproved reserves and undiscovered resources) also are assets. See paragraphs A43 through A47 and A73 through A78.
b. The valuation technique provided relies on readily available information. However, fair value, which would require additional information, may be a more appropriate valuation technique. See paragraphs A48 through A54.
c. This proposal requires use of existing sales volume and sales value information to determine an average price for end of period valuation. Use of market prices as of the end of the reporting period was considered. In addition to the relative cost of obtaining market values, the Board does not believe the valuation would be improved. See paragraph A82.
d. Information to calculate effective royalty rates is readily available and the proposal provides for their use in valuing estimated petroleum royalties. An alternative considered was the use of statutory provisions for certain types of leases. See paragraph A101.
e. Regional data is readily available and the proposal provides for its use in valuing estimated petroleum royalties. An alternative considered was the use of field by field data. See paragraphs A56 and A101.

INTRODUCTION

1. The purpose of this document is to solicit comments on proposed accounting standards for Federal oil and gas resources.
2. In late 2002, the Board began its deliberations on Federal natural resources. The Board decided that each type of natural resource (e.g., fluid leasable minerals such as oil and gas, and solid leasable minerals such as coal and timber) would be separately addressed in phases beginning with Federal oil and gas resources. Federal oil and gas resources were addressed first due to the literature available, the extensive historical information on Federal lease programs and royalty collections, and the large amount of oil and gas royalty collections made by the Federal government.
3. The proposed standards address the recognition of an asset, liability, revenue, expense, and gains and losses based on valuation of the asset at year-end. Disclosures are proposed for rights to future royalty streams identified for sale. Implementation guidance for proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources is proposed. The proposed standards also address disclosure requirements and RSI for Federal oil and gas resources not classified as proved reserves.
4. The proposed standards, if adopted, would be effective for periods ending after September 30, 2009.

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PROPOSED ACCOUNTING STANDARDS

Definitions in paragraphs 5 through 15 are presented first in the proposed accounting standards because of their uniqueness in calculating the asset value of estimated petroleum royalties. Other terms shown in **boldface type** the first time they appear in this document are presented in the Glossary (see page 75). Reviewers of this document may want to examine all definitions before reviewing the proposed accounting standards and Basis for Conclusions.

Definitions

5. Federal Oil and Gas Resources: Oil and gas resources over which the Federal government may exercise sovereign rights with respect to exploration and exploitation and from which the Federal government has the authority to derive revenues for its use. Federal oil and gas resources do not include resources over which the Federal government acts as a fiduciary for the benefit of a non-Federal party.
6. Regional Estimated Quantity of Proved Oil and **Lease Condensate** Reserves: The regional estimated quantities of proved oil and lease condensate reserves are those quantities of oil and lease condensate from Federal oil and gas resources that are totaled for a specified region. Quantities of oil and lease condensate are estimated in barrels (one barrel holds 42 U.S. gallons) at 60 degrees Fahrenheit.
7. Regional Estimated Quantity of Proved **Natural Gas Plant Liquids** Reserves: The regional estimated quantities of proved natural gas plant liquids (NGPLs) reserves are those quantities of NGPLs from Federal gas resources that are totaled for a specified region. Quantities of NGPLs are estimated in barrels (one barrel holds 42 U.S. gallons) at 60 degrees Fahrenheit.
8. Regional Estimated Quantity of Proved Gas Reserves: The regional estimated quantities of proved gas reserves are those quantities of **dry gas** from Federal gas resources that are totaled for a specified region. Quantities of gas are estimated in thousands of cubic feet (Mcf) at 14.73 pounds per square inch absolute (PSIA) at 60 degrees Fahrenheit.
9. Regional Average First Purchase Price for Oil and Lease Condensate: The regional average **first purchase price** for oil and lease condensate is calculated by dividing the total regional **sales value** of oil and lease condensate produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months by the total regional **sales volume** of oil and lease condensate produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months. All types of crude **oil streams** and **gravity bands** are aggregated for this calculation.
10. Regional Average First Purchase Price for NGPLs: The regional average first purchase price for NGPLs is calculated by dividing the total regional sales value of NGPLs produced from Federal gas resources in each

associated region for the preceding twelve (12) months by the total regional sales volume of NGPLs produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months.

11. Regional Average Wellhead Price for Gas: The regional average wellhead price for gas is calculated by dividing the total regional sales value of dry gas produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months by the total regional sales volume of dry gas produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months.

12. Effective Regional Average Royalty Rate for Oil and Lease Condensate: The effective regional average royalty rate for oil and lease condensate is calculated by dividing the royalty value (royalties) earned on the oil and lease condensate reserves produced for each associated region for the preceding twelve (12) months by the total sales value of that production for the preceding twelve (12) months.

13. Effective Regional Average Royalty Rate for NGPLs: The effective regional average royalty rate for NGPLs is calculated by dividing the royalty value (royalties) earned on the NGPL reserves produced for each associated region for the preceding twelve (12) months by the total sales value of that production for the preceding twelve (12) months.

14. Effective Regional Average Royalty Rate for Gas: The effective regional average royalty rate for gas is calculated by dividing the royalty value (royalties) earned on the dry gas reserves produced for each associated region for the preceding twelve (12) months by the total sales value of that production for the preceding twelve (12) months.

15. Regional Estimated Petroleum Royalties: Regional estimated petroleum royalties means the estimated end-of-period value of the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources in each region.

Asset Recognition

16. The Federal government's estimated petroleum royalties shall be recognized as an asset on the balance sheet of the component entity that is responsible for collecting royalties. The value of the Federal government's estimated petroleum royalties shall be computed based on the calculation of oil and lease condensate estimated petroleum royalties, NGPLs estimated petroleum royalties, and gas estimated petroleum royalties on a regional basis. Formulas to be used to calculate the estimated petroleum royalties for oil and lease condensate, NGPLs, and gas on a regional basis are as follows:

For oil and lease condensate:

Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves X Regional Average First Purchase Price for Oil and Lease Condensate X Effective Regional Average Royalty Rate for Oil and Lease Condensate = Regional Estimated Petroleum Royalties for Oil and Lease Condensate

For NGPLs:

Regional Estimated Quantity of Proved NGPLs Reserves X Regional Average First Purchase Price for NGPLs X Effective Regional Average Royalty Rate for NGPLs = Regional Estimated Petroleum Royalties for NGPLs

For gas:

Regional Estimated Quantity of Proved Gas Reserves X Regional Average Wellhead Price for Gas X Effective Regional Average Royalty Rate for Gas = Regional Estimated Petroleum Royalties for Gas

17. For purposes of these standards, the regions used in determining and reporting regional amounts or factors shall be collaboratively developed by all the component entities involved in oil and gas resource activities. Regions used in calculating Regional Estimated Petroleum Royalties and in applying these standards shall be consistent and aligned with regions used internally by the component entities in administering Federal oil and gas resource activities.

18. The values of estimated petroleum royalties calculated for oil and lease condensate on a regional basis, NGPLs calculated on a regional basis, and gas calculated on a regional basis shall be added together to provide the total value of estimated petroleum royalties for the Federal government.

19. Detailed guidance for the valuation of estimated petroleum royalties is provided in the “Asset Valuation Guidance” section of these standards, beginning at paragraph 37.

Liability Recognition

20. A liability for revenue distributions to others shall be recognized on the balance sheet of the component entity that is responsible for collecting royalties in conjunction with the recognition of an asset for estimated petroleum royalties. The amount of the liability shall be estimated based on the royalty share of the Federal proved oil and gas reserves designated to be distributed to others, e.g., the states, the general fund of the U.S. Treasury and other federal agencies. For example, the average annual share of the revenue distributed to others over the preceding 12 months may be an acceptable basis for estimating petroleum royalties to be distributed to others. Other methodologies may be acceptable.

Revenue and Expense Recognition

21. Exchange revenue recognition is based on Statement of Federal Financial Accounting Standards (SFFAS) 7, *Accounting for Revenue and Other Financing Sources*, paragraph 34.

22. **Bonus bid** and **rent** revenue relating to Federal oil and gas resources shall be recognized as exchange revenue on the Statement of Net Cost of the component entity that is responsible for collecting royalty revenue. In addition, a liability[7] and corresponding expense and/or transfer out for bonus bid and rent revenue distributions to others shall be recognized by the component entity that is responsible for collecting royalties in conjunction with the recognition of the bonus bid and rent revenue. The amount of the liability shall be the bonus bid and rent revenues designated to be distributed to others, e. g., the states, the general fund of the U.S. Treasury and other federal agencies. The corresponding expense and/or transfer out shall be recognized in a manner consistent with existing standards.

23. **Royalties** from the production of proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources shall be recognized as exchange revenue on the Statement of Net Cost by the component entity that is responsible for collecting the royalty revenue. At the same time, an amount equal to the royalty revenue shall be recognized as depletion expense on the Statement of Net Cost of the component entity that is responsible for collecting the royalty revenue; and, the value of estimated petroleum royalties shall be reduced by the depletion expense amount.[8]

Future Royalty Rights Identified for Sale

24. When rights to a stream of future royalties are identified for sale, the calculated value of those rights shall be disclosed in the notes as "future royalty rights identified for sale." The "future royalty rights identified for sale" shall not be revalued or reclassified to a different asset category on the balance sheet and no gain or loss shall be reported prior to the sale.

25. The calculated value disclosed for future royalty rights identified for sale shall be based on the estimated quantity of proved reserves for the specific **field** to be sold; the first purchase price for oil and lease condensate, the

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[7] SFFAS 1, *Accounting for Selected Assets and Liabilities,* par. 83-86, provides that other current liabilities may include unpaid expenses that are accrued for the fiscal year for which the financial statements are prepared and are expected to be paid within the fiscal year following the reporting date. Amounts of bonus bids and rent revenues to be distributed to others may be classified as an other current liability consistent with SFFAS 1 if the definition is met.

[8] The principle that a liability is reduced when funds are distributed is established in other FASAB standards. When bonus bid, rent, and royalties are distributed, the liability for bonus bid, rent, and royalty distributions should be reduced.

first purchase price for NGPLs, or the wellhead price for gas for the specific field to be sold; and the royalty rate for the specific field to be sold.

26. When the future royalty rights identified for sale are sold, the calculated value of the future royalty rights sold shall be based on the quantity of proved reserves sold, the first purchase price for oil and lease condensate, the first purchase price for NGPLs, or the wellhead price for gas for the specific field, and the royalty rate for the specific field. This calculated value shall be removed from the estimated petroleum royalties account at the time of the sale. Any difference between this calculated value and the actual sales proceeds results in a net gain or loss. The net gain or loss shall be reported on the Statement of Net Cost of the component entity that is responsible for collecting royalties. In addition, if the sale produced a net gain, the liability and a corresponding expense and/or transfer-out for the revenue distributions to others shall be increased by an amount equal to the amount of the gain designated to be distributed to others, e.g., the states, the general fund of the U.S. Treasury and other federal agencies. If the sale produced a net loss, the liability and a corresponding expense and/or transfer-out for the revenue distributions to others shall be decreased by an amount equal to the amount of the loss, which will reduce future distributions to others.

Valuing the Estimated Petroleum Royalties

27. The estimated petroleum royalties asset shall be valued at the end of each year for financial statement reporting. Detailed guidance for the calculation of the value of estimated petroleum royalties at year-end is provided in the "Asset Valuation Guidance" section of these standards, beginning at paragraph 37.

28. The calculated value of estimated petroleum royalties at year-end shall be compared to the existing book value of the estimated petroleum royalties asset. If the calculated value of the estimated petroleum royalties asset at year-end is greater than the book value,[9] the book value shall be increased to the new estimate and a gain shall be recorded on the Statement of Net Cost. If the calculated value of the estimated petroleum royalties asset at year-end is less than the book value, the book value shall be decreased to the new estimate and a loss shall be recorded on the Statement of Net Cost.

29. In addition, if the calculated value of the estimated petroleum royalties asset at year-end is greater or less than the book value, the liability for revenue distributions to others shall be increased or decreased to the amount expected to be distributed. For example, the average annual share of the revenue distributed to others over the preceding 12 months may be

[9] The estimated petroleum royalties beginning balance would have been reduced by the amount expensed on the Statement of Net Cost.

an acceptable basis to estimate future distributions. Other methodologies may be acceptable.

Disclosures and Required Supplementary Information

30. Notes to the financial statements are an integral part of the basic financial statements, essential for complete and fair presentation in conformity with generally accepted accounting principles for the Federal government.

Component Entity Disclosures

31. The component entity responsible for reporting the Federal government's estimated petroleum royalties on its balance sheet shall provide the following as note disclosures:

    a. A concise statement explaining how the management of Federal oil and gas resources is important to the overall mission of the entity.
    b. A brief description of the entity's stewardship policies for Federal oil and gas resources. The stewardship policies for Federal oil and gas resources shall describe the guiding principles established to: assess the oil and gas resource areas; offer those resources to interested developers; sell and assign leases to winning bidders; administer the leases; collect bonuses, rents, royalties, and royalty-in-kind; and distribute the collections consistent with statutory requirements, prohibitions, and limitations governing the entity.
    c. A narrative describing future royalty rights identified for sale. The narrative shall provide the value of the rights identified for future sale, the location of the field involved in the future sale, and the best estimate of when the rights would be sold.
    d. A narrative describing and a display showing earned revenue reported by category for the reporting period shall be presented for offshore and onshore revenues for the following categories: royalty revenue earned for oil and lease condensate, royalty revenue earned for NGPLs, royalty revenue earned for gas, earned rent revenue, earned bonus bid revenue for leases, and total revenue from all the above categories.
    e. A narrative describing and a display showing:

        i. The quantity of oil and lease condensate, NGPLs, and gas for each reporting period.
        ii. The average of the Regional Average First Purchase Prices for oil and lease condensate, the average of the Regional Average First Purchase Prices for NGPLs, and the average of the Regional Average Wellhead Prices for gas for each reporting period.
        iii. The average royalty rate oil and lease condensate, NGPLs, and gas for each reporting period.
        iv. The asset value for oil and lease condensate, the asset value for NGPLs, and the asset value for gas for each reporting period.
        v. The value of estimated petroleum royalties at the end of each reporting period.

Component Entity Required Supplementary Information (RSI)

32. The component entity responsible for reporting the Federal government's estimated petroleum royalties on its balance sheet shall provide the following as RSI:

    a. A narrative describing and a display showing the most current and complete information available for **technically recoverable resources**. The most current information for technically recoverable resources maintained by the Energy Information Administration (EIA) shall serve as the basis for this information. The information shall include the estimated quantity of offshore technically recoverable resources from Federal oil and gas resources, the estimated quantity of onshore technically recoverable resources from Federal oil and gas resources, the as-of-date for the information being presented, and a brief explanation of changes to the information from the previous reporting period.

    b. A narrative describing and a display showing the following information for each region that was identified for use in calculating the Federal government's total estimated petroleum royalties:

        i. The sales volume, the sales value, the royalty revenue earned, and the **estimated value for royalty relief** for oil and lease condensate produced from Federal oil and gas resources for the reporting period shall be added together in each region and reported.

        ii. The sales volume, the sales value, the royalty revenue earned, and the estimated value for royalty relief for NGPLs produced from Federal gas resources for the reporting period shall be added together in each region and reported.

        iii. The sales volume, the sales value, the royalty revenue earned, and the estimated value for royalty relief for gas produced from Federal gas resources for the reporting period shall be added together in each region and reported.

    c. A narrative describing and a display showing the following historical information about proved oil and lease condensate, NGPLs, and gas reserves from Federal leases for each of the preceding ten calendar years: adjustments; net revisions; revisions and adjustments; net of sales and acquisitions; extensions; new field discoveries; discoveries in old fields; total discoveries; estimated production; proved reserves; and change from prior year. Definitions for these terms are contained in the Glossary under the subheading **"Historical Estimates of Proved Reserves."**

Consolidated Financial Report (CFR) of the United States Government Disclosures

33. The disclosure related to Federal oil and gas resources shall provide:

a. A concise statement explaining the nature and valuation of Federal oil and gas resources.
b. A narrative describing and a display showing:

   i. The quantity of oil and lease condensate, NGPLs, and gas for each reporting period.
   ii. The average of the Regional Average First Purchase Prices for oil and lease condensate, the average of the Regional Average First Purchase Prices for NGPLs, and the average of the Regional Average Wellhead Prices for gas for each reporting period.
   iii. The average royalty rate for oil and lease condensate, NGPLs, and gas for each reporting period.
   iv. The asset value for oil and lease condensate, the asset value for NGPLs, and the asset value for gas for each reporting period.
   v. The value of estimated petroleum royalties at the end of each reporting period.
c. A reference to specific agency reports for additional information about oil and gas resources.

<u>Disclosure Requirements for Fiduciary Oil and Gas Resources</u>

34. Fiduciary activities are defined in SFFAS 31, *Accounting for Fiduciary Activities*. Information consistent with the requirements of paragraphs 16 through 29 and 37 through 45 of this document shall be presented as an integral part of the fiduciary activities Schedules of Fiduciary Activity and Net Assets. No additional disclosures or RSI are required by this standard.

Implementation Guidance

35. The Federal government's estimated petroleum royalties shall be recognized as an asset as of the beginning of the reporting period in which the standards become effective. The estimated petroleum royalties shall be recognized on the balance sheet of the component entity responsible for collecting royalties. In addition, an offsetting liability shall be recognized for the amount of revenues designated for distribution to others.

36. The cumulative net effect of adopting this proposed accounting standard shall be reported as a "change in accounting principle." The adjustment shall be made to the beginning balance of cumulative results of operations on the Statement of Changes in Net Position for the period that the change is made in accordance with SFFAS 21, *Reporting Corrections of Errors and Changes in Accounting Principles*. In the initial year of implementation, prior year information shall not be restated.

Asset Valuation Guidance

37. The following detailed guidance describes how the value of estimated petroleum royalties should be calculated for transition to these proposed standards and for valuation of estimated petroleum royalties for financial statement reporting at subsequent years-end. The value of the Federal

government's estimated petroleum royalties is to be based on the calculation of oil and lease condensate estimated petroleum royalties, NGPLs estimated petroleum royalties, and gas estimated petroleum royalties on a regional basis. Formulas to be used to calculate the estimated petroleum royalties for oil and lease condensate, NGPLs, and gas on a regional basis are as follows:

<u>For oil and lease condensate:</u>

Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves X Regional Average First Purchase Price for Oil and Lease Condensate X Effective Regional Average Royalty Rate for Oil and Lease Condensate = Regional Estimated Petroleum Royalties for Oil and Lease Condensate

<u>For NGPLs:</u>

Regional Estimated Quantity of Proved NGPLs Reserves X Regional Average First Purchase Price for NGPLs X Effective Regional Average Royalty Rate for NGPLs = Regional Estimated Petroleum Royalties for NGPLs

<u>For gas:</u>

Regional Estimated Quantity of Proved Gas Reserves X Regional Average Wellhead Price for Gas X Effective Regional Average Royalty Rate for Gas = Regional Estimated Petroleum Royalties for Gas

38. Based on quantity information from an annual survey conducted by the EIA, the estimated quantities of proved oil and lease condensate reserves from Federal oil and gas resources are to be added together in each region, the estimated quantities of proved NGPLs reserves from Federal gas resources are to be added together in each region, and the estimated quantities of proved gas reserves from Federal gas resources are to be added together in each region. These calculations will provide the regional estimated quantity of proved oil and lease condensate reserves, the regional estimated quantity of NGPLs reserves, and the regional estimated quantity of proved gas reserves, respectively. The most recent survey conducted by the EIA, issued no more than twelve (12) months before the end of the reporting period, will serve as the basis for quantity, or volume, information. Adjustments for material known changes (e.g., new discoveries or adjustments in estimates) during the reporting period but after the date of the survey will be made; however, a comprehensive re-estimate is not required. For purposes of this standard, proved lease condensate reserves are to be included with the proved oil reserves.

39. Each regional estimated quantity of proved oil and lease condensate reserves combined is to be multiplied by the associated regional average first purchase price for oil and lease condensate. These calculations will provide the regional sales value of proved oil and lease condensate

reserves from oil and gas fields that are leased from the Federal government for each region.

40. Each regional estimated quantity of proved NGPLs reserves is to be multiplied by the associated regional average first purchase price for NGPLs. These calculations will provide the regional sales value of proved NGPL reserves from gas fields that are leased from the Federal government for each region.

41. Each regional estimated quantity of proved gas reserves is to be multiplied by the associated regional average wellhead price for gas. These calculations will provide the regional sales value of proved gas reserves from gas fields that are leased from the Federal government for each region.

42. Each regional sales value of proved oil and lease condensate reserves from oil fields that are leased from the Federal government is to be multiplied by the associated effective regional average royalty rate for oil and lease condensate. These calculations will provide the value of estimated petroleum royalties for oil and lease condensate from oil fields that are leased from the Federal government for each region.

43. Each regional sales value of proved NGPL reserves from gas fields that are leased from the Federal government is to be multiplied by the associated effective regional average royalty rate for NGPLs. These calculations will provide the value of estimated petroleum royalties for NGPLs from gas fields that are leased from the Federal government for each region.

44. Each regional sales value of proved gas reserves from gas fields that are leased from the Federal government is to be multiplied by the associated effective regional average royalty rate for gas. These calculations will provide the value of estimated petroleum royalties for gas from gas fields that are leased from the Federal government for each region.

45. The values of estimated petroleum royalties for oil and lease condensate for each region, the values of estimated petroleum royalties for NGPLs for each region, and the values of estimated petroleum royalties for gas for each region are to be added together to provide the total value of estimated petroleum royalties. This total value would be the Federal government's estimated petroleum royalties to be recognized as an asset and reported on the balance sheet of the component entity that is responsible for collecting royalty revenue.

Effect on Existing Standards

46. This standard affects existing standards dealing with "bonus bid, rent, and royalty revenues" in SFFAS 7. As a result, paragraph 45 of SFFAS 7 is amended as follows:

> [45] Under exceptional circumstances, such as revenues from the auction of the radio spectrum ~~rents and royalties on the~~

~~Outer Continental Shelf~~, an entity recognizes virtually no costs (either during the current period or during past periods) in connection with earning revenue that it collects.

47. In addition, paragraphs 275, 276, and 277 of SFFAS 7 are deleted.

Effective Date

48. These standards are effective for periods ending after September 30, 2009. Early implementation is permitted.

The provisions of this statement need not be applied to immaterial items.

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APPENDIX A: BASIS FOR CONCLUSIONS

This appendix discusses some factors considered significant by members in reaching the conclusions in the proposed standards. It includes the reasons for accepting certain approaches and rejecting others. Some factors were given greater weight than other factors. The guidance enunciated in the standards---not the material in this appendix---should govern the accounting for specific transactions, events, or conditions.

Current Project

A1. The project began with the formation of a task force to conduct research. The task force produced a discussion paper in June 2000 entitled *Accounting for the Natural Resources of the Federal Government*. (See http://www.fasab.gov/reports.htm to access the report.) In 2002, the Board resumed active consideration of the issues raised by the task force after a deferral to address other issues.

A2. The Board was interested in determining whether values for Federal natural resources, or some surrogate, should be capitalized and reported on the balance sheet. The Board members believed that capitalizing Federal natural resources could increase accountability for their management and improve the comprehensiveness, relevance, and consistency of Federal financial statements. The Board members agreed to address each type of natural resource (e.g., fluid leasable minerals such as oil and gas, solid leasable minerals such as coal and timber) in separate phases. Federal oil and gas resources were addressed first because of the literature available in other domains, the extensive historical information on Federal lease programs and royalty collections, and the large amount of revenue earned in exchange for oil and gas resources.

A3. The Board indicated that the pertinent questions were (1) what, if anything, should be recognized as an asset; and, (2) what is the source and reliability of quantity information. They believed the source and the reliability of the information would have a bearing on where information should be reported.

A4. The extractive industries' activities for oil and gas can be divided into two categories—upstream activities and downstream activities. Upstream activities are divided into the following phases:

a. Prospecting[10]
b. Acquisition of mineral rights
c. Exploration
d. Appraisal and evaluation
e. Development
f. Production

[10] Prospecting usually involves researching and analyzing an area's historic geologic data; and, carrying out topographical, geological, and geophysical studies.

A5. Downstream activities take place after the production phase of the upstream activities through to the point of sale.

A6. The national assessment of oil and gas resources performed by the Federal government is similar to the prospecting phase of the extractive industries' upstream activities. It is the only activity performed by the Federal government that is similar to the extractive industries' activities.

A7. The Board noted that, based on discussions about oil and gas lease activities in the private sector, new models for accounting and reporting the Federal government's oil and gas activities would be needed because Federal activities are not similar to private sector activities and the current Federal model is incomplete.

Overview of Federal Oil and Gas Resources

A8. A *Framework for Components of Federal Oil and Gas Resources* (framework) is presented on page 20, which identifies the universe of Federal oil and gas resources. The framework presents accounting standards requirements and the components of federal oil and gas resources (total resources*)*. Total resources incorporate "original in-place" resources, that is, resources in the earth before human intervention.

A9. The accounting standards presented in the framework include current accounting standards and proposed accounting standards for each component of Federal oil and gas resources. The components are those used in the industry. Information is available in varying degrees and with varying reliability for each component. The components are first separated into "undiscovered resources" and "discovered resources." Generally, undiscovered resources are not under lease, while, discovered resources are under lease.

<u>Undiscovered Resources</u>

A10. The first major component of total resources is **undiscovered resources**. The undiscovered resources component is divided into the following subcomponents:

a. **undiscovered nonrecoverable resources**
b. **undiscovered recoverable resources**
    i. **undiscovered conventionally recoverable resources**
    ii. **undiscovered economically recoverable resources**.

A11. Each component and subcomponent can be further divided between onshore and offshore resources. Onshore resources consist of resources on Federal lands. Offshore resources consist of resources on the Outer Continental Shelf (OCS). This division between onshore and offshore resources is important operationally because the source and volume of information varies.

A12. There is no information available on undiscovered nonrecoverable resources. These resources are not addressed or included in any type of assessment. Undiscovered nonrecoverable resources are referred to as resources that are beyond conventional technologies to be estimated and are not assessed. However, in the realm of "original in-place" resources they may exist.

A13. Information on the two subcomponents of undiscovered recoverable resources is available for offshore oil and gas resources. This information is based on national assessments performed by the Minerals Management Service (MMS) approximately every 5 years, with updates on a yearly basis for certain geographic locations. The assessment considers recent geophysical, geological, technological, and economic information and uses a geologic play analysis approach for resource appraisal. Information on undiscovered conventionally recoverable resources and undiscovered economically recoverable resources is provided in the MMS assessment.

A14. For the onshore portion of undiscovered recoverable resources, the U.S. Geological Survey (USGS) formerly conducted national assessments. The last comprehensive national assessment was completed by the USGS in 1995, and since 2000 the USGS has been re-assessing basins of the U.S. that are considered to be priorities for the new assessment rather than assessing all of the basins of the U.S. As each basin is re-assessed, the assessment results are added to the assessment tables, and these new values replace the assessment results from 1995. The USGS assessment provides information on undiscovered conventionally recoverable resources but not on undiscovered economically recoverable resources like the MMS does.

A15. Under current FASAB accounting standards, there are no requirements to provide or present information about the undiscovered resource components in the financial statements. Under the proposed accounting standards, information about onshore and offshore undiscovered recoverable resources would be included in the technically recoverable resources and reported as required supplementary information (RSI). Information about technically recoverable resources is gathered and maintained by the EIA.

Discovered Resources

A16. The second major component of total resources is **discovered resources**. The discovered resources component is divided into the following subcomponents as follows:

a. **unproved reserves**
    i. **unproved possible reserves**
    ii. **unproved probable reserves**

b. proved reserves
    i. **proved undeveloped reserves**

ii. **proved developed reserves**

i) **proved developed non-producing reserves**
ii) **proved developed producing reserves**

c. production

A17. Under current FASAB accounting standards, there are no requirements to provide or present information about the unproved reserves components in the financial statements.

A18. Quantitative information in relation to onshore and offshore proved reserves, including new discoveries, production, and adjustments is submitted to the EIA by oil and gas well operators once a year. The due date for operators to submit the information is April 15 for activities from the preceding calendar year.

A19. Under current accounting standards, the bonus bid, rent (earned on the lease until oil and gas production begins), and royalty revenue (earned on production) are accounted for as a custodial activity (i.e., an amount collected for others) by MMS-the collecting entity. The revenue and its distribution are reported on MMS's Statement of Custodial Activities. Component entities receiving a distribution and the CFR of the United States government recognize the revenue as a financing source in their respective Statement of Changes in Net Position or Statement of Operations and Changes in Net Position.

A20. Under the proposed accounting standards, information about onshore and offshore unproved reserves would be included in the technically recoverable resources and reported as RSI. Information about technically recoverable resources is gathered and maintained by the EIA.

A21. In addition, under the proposed accounting standards, the estimated Federal royalty share of proved reserves would be recognized as estimated petroleum royalties by the component entity responsible for reporting the asset on its balance sheet. Also, royalty revenue earned would be recognized as revenue along with a depletion expense in equal amounts on the Statement of Net Cost. Changes in the asset amount due to year-end valuation would be reported as a gain or loss on the Statement of Net Cost of the component entity responsible for reporting the asset on its balance sheet. Also, collections for rent and bonus bids would be recognized as exchange revenue on the Statement of Net Cost. Any expenses incurred to collect the rent and bonus bids would be included in the operating expenses on the Statement of Net Cost. The CFR would include these amounts in the consolidated financial statements.

A22. There are no current requirements to provide or present information about the production of oil and gas in the financial statements. However, under the proposed accounting standards, historical information on the quantity and consumption of proved reserves, including the sales volume of proved reserves, the sales value of proved reserves, the amount of royalty revenue earned, and the estimated value for royalty relief would be provided as RSI.

A23. On the following page, Illustration 1, entitled *Framework for Components of Federal Oil and Gas Resources*, provides a summary of the information presented in the preceding paragraphs. The shaded boxes in the illustration represent the availability of information as follows:

No quantity information available	
Technically recoverable resources quantity information provided by EIA	
Proved reserves quantity information provided by EIA	

A24. The terms in Illustration 1 are defined in the Glossary under the subheading *Definitions of Resource and Reserve Components and Subcomponents*.

Illustration 1 Framework for Components of Federal Oil and Gas Resources

<table>
<tr><td>Accounting Standards</td><td colspan="9">Components of Federal Oil and Gas Resources</td></tr>
<tr><td rowspan="5"></td><td colspan="3">Undiscovered Resources</td><td colspan="6">Discovered Resources</td></tr>
<tr><td rowspan="2">Undiscovered Non-Recoverable Resources</td><td colspan="4">Technically Recoverable Resources</td><td colspan="3" rowspan="2">Proved Reserves</td><td rowspan="2">Production</td></tr>
<tr><td colspan="2">Undiscovered Recoverable Resources</td><td colspan="2">Unproved Reserves</td></tr>
<tr><td rowspan="2"></td><td>Undiscovered Conventionally Recoverable Resources</td><td>Undiscovered Economically Recoverable Resources</td><td>Unproved Possible Reserves</td><td>Unproved Probable Reserves</td><td>Proved Undeveloped Reserves</td><td colspan="2">Proved Developed Reserves</td><td></td></tr>
<tr><td colspan="2"></td><td colspan="3"></td><td>Proved Developed Non-Producing Reserves</td><td>Proved Developed Producing Reserves</td><td></td></tr>
<tr><td>Current Accounting Standards</td><td colspan="3"></td><td colspan="5">Bonus Bid, Rent, Royalty Revenue Accounted as a Financing Source on the CFR Statement of Operations and Changes in Net Position</td><td></td></tr>
<tr><td>Proposed Accounting Standards</td><td></td><td colspan="2">Provide RSI Information for Undiscovered Recoverable Resources</td><td colspan="2">Recognize Bonus Bid and Rent Revenues as exchange revenue on SNC[11]
Provide RSI Information for Unproved Reserves</td><td colspan="3">• Recognize Federal Royalty Share on BS[12]
• Recognize Royalty Revenues as Revenue and Depletion Expense on SNC
• Recognize Gains/Losses on SCNP[13]
• Provide Disclosure for Proved Reserves</td><td>Provide RSI/ Disclosure Information – Quantitative and Financial</td></tr>
</table>

[11] Statement of Net Cost
[12] Balance Sheet
[13] Statement of Changes in Net Position

Federal Entities Involved in Federal Oil and Gas Resources

A25. There are three Federal government entities involved in the major Federal oil and gas resources activities. They are: 1) Bureau of Land Management (BLM), Department of Interior; 2) Minerals Management Service (MMS), Department of Interior; and 3) Energy Information Administration (EIA), Department of Energy. Each entity's involvement is described in the following overview paragraphs.

A26. **BLM Overview**. BLM manages 262 million acres of mostly Western land and 700 million acres of subsurface mineral estate nationwide. These lands are managed for multiple-use and on a sustained-yield basis with BLM's 5-year Strategic Plan and Annual Performance Plan as the foundation. There is no 5-year plan for oil and natural gas lease sales. The BLM's management responsibilities include recreation opportunities, commercial activities, and other natural resource activities.

A27. Under its "commercial activities" management responsibility, the BLM is responsible for leasing oil and gas resources on all Federally owned lands, including those lands managed by other Federal agencies. BLM is responsible for review and approval of permits and licenses to explore, develop, and produce oil and gas resources on both Federal and Indian lands. BLM is also responsible for inspection of oil and gas wells and other development operations to ensure through enforcement authorities that lessees and operators comply with lease requirements and regulations. Although the Bureau of Indian Affairs issues leases on Indian lands, BLM handles the operational approvals and supervision of operations on these lands, and the MMS makes bonus, rent, and royalty collections for these lands.

A28. **MMS Overview**. The mission of MMS is to manage the mineral resources on the nation's Outer Continental Shelf in an environmentally sound and safe manner; and, to collect, verify, and distribute, in a timely fashion, mineral revenues generated from Federal (onshore and offshore) and Indian lands. These activities are performed under the following two programs:
- *Offshore Minerals Management.*—This program provides for 1) performance of environmental assessments to ensure compliance with the National Environmental Policy Act (NEPA); 2) conduct of lease offerings; 3) selection and evaluation of tracts offered for lease by competitive bidding; 4) assurance that the Federal Government receives fair market value for leased lands; and 5) regulation and supervision of energy and mineral exploration, development, and production operations on the OCS lands.
- *Minerals Revenue Management*.—This program provides for the collection and distribution of royalties, rents, and bonuses due the Federal government and Indian lessors from minerals produced on Federal onshore, OCS, and Indian lands in accordance with various laws.

A29. **EIA Overview**. The primary focus of EIA's reserves program is providing accurate annual estimates of U.S. proved reserves of crude oil, dry gas, and natural gas plant liquids. These estimates are essential to the development, implementation, and evaluation of national energy policy and legislation. In the past, the Government and the public relied upon industry estimates of proved reserves. However, the industry ceased publication of reserve estimates.

A30. In response to a recognized need for credible annual proved reserves estimates, Congress, in 1977, required the Department of Energy to prepare such estimates. To meet this requirement, the EIA developed a program that established a unified, verifiable, comprehensive, and continuing annual statistical series for proved reserves of crude oil and natural gas. It was expanded to include proved reserves of natural gas liquids for the 1979 and subsequent reports.

A31. The EIA makes energy forecasts to help government, industry, and the public understand the direction and trends implied by current events and decisions. Most of EIA's forecasts focus on energy supply, demand, and price projections for the United States and for the world. EIA has two general projection periods -- the short term (next six-to-eight quarters) and the mid-term (approximately the next 20 years). The projections integrate all fuel types, using the British thermal unit (Btu) as a common unit of measure, for a comprehensive overview balancing energy supply with energy demand.

Conceptual Aspects of Oil and Gas Resources as a Federal Asset with a Related Liability

A32. The Board has undertaken a project to complete its conceptual framework. Currently, the conceptual framework does not include a statement addressing definitions and recognition of elements such as assets and liabilities. However, SFFAS 1, *Accounting for Selected Assets and Liabilities of the Federal Government*, presents an asset definition in the basis for conclusions and SFFAS 5, *Accounting for Liabilities of the Federal Government,* includes a liability definition and liability recognition criteria.

A33. The GAAP hierarchy provides that statements of federal financial accounting standards constitute level A (the highest level) guidance. Statements of federal financial accounting concepts are not GAAP. Instead, concepts statements constitute “other literature” and may only be relied upon by financial statement preparers and auditors to resolve specific accounting issues in the absence of GAAP literature. In developing and amending accounting standards, the Board looks to concepts statements for guiding principles and also considers relevant existing standards and guidance issued by the Board and other standard setting bodies. Until the Board amends existing standards, the Board expects practice to be governed by the definitions embodied in the four levels of the GAAP hierarchy. Thus, the Board distinguishes between definitions presented in concepts which are used to guide Board deliberations on future GAAP and definitions presented in standards which constitute current GAAP.

A34. The standards embodied in SFFAS 1 are based on the following definition of an asset:

> “The term asset as used in this document means an item that embodies a probable future economic benefit that can be obtained or controlled by

the federal government or a reporting entity as a result of past transactions or events."[14]

A35. The SFFAS 5 definition of liability is:

> "A liability is a probable future outflow or other sacrifice of resources as a result of past transactions."[15]

A36. The Board believes that the accounting for oil and gas resources presented in this proposed standard would be the same using either the definitions in SFFAS 1 and 5 or using the definitions contained in the proposed concepts statement. The following paragraphs provide an analysis of accounting for oil and gas resources based on the definitions in the proposed concepts statement.

Definition of Asset

A37. In the exposure draft (ED), Proposed Statement of Federal Financial Accounting Concepts: *Definition and Recognition of Elements of Accrual-Basis Financial Statements* (hereafter referred to as Elements ED), the proposed definition[16] of an asset is:

> "An asset is a resource that embodies economic benefits or services that the Federal government can control. To be an asset of the federal government, a resource must possess two characteristics. First, it embodies economic benefits or services that can be used in the future. Second, the government controls access to the economic benefits or services and, therefore, can obtain them and deny or regulate the access of other entities."[17]

A38. Assets may vary in specific form and nature; e.g., they may be tangible/intangible, monetary/non-monetary, current/non-current, and more certain benefits/less certain benefits.

Recognition Criteria

A39. Recognition criteria are the conditions an item should meet to be recognized in financial statements. The recognition criteria proposed in the Elements ED are (a) the item meets the definition of an element of financial statements and (b) the item is measurable. As used in the Elements ED, the term measurable

[14] SFFAS 1, paragraph 93.
[15] SFFAS 5, paragraph 19.
[16] While the Elements ED has not been finalized and wording changes are still being considered by the Board, the Board's considerable work on "asset" and "liability" definitions—including consideration of current and evolving notions of assets and liabilities by other standard setters—suggests that the issues of whether an asset exists and/or a liability arises in the context of oil and gas proved reserves and arrangements to distribute the related royalty revenue are not controversial. The Board does not believe that revisions to the proposed Elements ED would impact this proposal. Further, the Board believes that input from respondents regarding this application of the evolving definitions may be helpful to both ongoing projects.
[17] Elements ED, paragraphs 17 and 21.

means quantifiable in monetary units. In recent deliberations, the Board has considered modifying this definition of measurable to provide that an item is measurable if it can be determined with reasonable certainty or is reasonably estimable.

A40. Conclusions about the existence of an element require judgment as to whether, based on the available evidence, the item possesses the essential characteristics of that element. The measurement of an element being considered for recognition in the financial statements often will require estimates and approximations. Measurement also may require a more rigorous assessment of the probability of future inflows or outflows of resources to enhance the reliability of amounts recognized in the financial statements. Recognition decisions also are influenced by assessments of the materiality and benefit versus cost of recognizing the results of the measurement of elements.

A41. Given the Elements ED definition of 'asset' and criteria for 'recognition', the next step the Board took was to consider 'measurability.' In its Statement of Financial Accounting Concepts (SFAC) 5, the Financial Accounting Standards Board (FASB) acknowledges that its current standards as well as other literature related to generally accepted accounting principles (GAAP) for entities other than government entities are based on a variety of measurement attributes and that it expects that practice to continue. Although many of the assets recognized under FASAB principles are measured using some form of historical cost, FASAB also currently follows a multi-attribute measurement approach; e.g., net realizable value for some receivables, present value for capital leases, etc. FASAB will continue to follow a multi-attribute approach for the near term.

Oil and Gas Resources as a Federal Asset

A42. First, the Board established which Federal oil and gas resources were being considered. Illustration 1, entitled *Framework for Components of Federal Oil and Gas Resources*, presents the oil and gas resources that were considered. The two major components are "undiscovered resources" and "discovered resources." All of the Federal oil and gas resources meet the definition of asset. Federal oil and gas resources qualify as federal government assets because the government can obtain the economic benefits and regulate the access of other entities as provided under federal law.

Oil and Gas Resources to be Recognized as a Federal Asset

A43. Since all Federal oil and gas resources controlled by the Federal government are assets, the Board's next step was to decide whether the Federal oil and gas resources "asset" should be recognized on a Federal component entity balance sheet. As noted above, the second criterion for recognition is that the asset "…is measurable."

A44. Estimates of the quantity of oil and gas resources other than proved reserves are available through EIA. With this quantity information, a monetary measure is technically feasible and, therefore, the asset qualifies for consideration for recognition. However, the Board does not believe that the information is sufficiently reliable to be recognized in a cost-beneficial manner.

A45. Statement of Federal Financial Accounting Concepts (SFFAC) 1 provides the following with respect to reliability:

> 160. Financial reporting should be reliable; that is, the information presented should be verifiable and free from bias and should faithfully represent what it purports to represent. To be reliable, financial reporting needs to be comprehensive. Nothing material should be omitted from the information necessary to represent faithfully the underlying events and conditions, nor should anything be included that would likely cause the information to be misleading to the intended report user. Reliability does not imply precision or certainty, but reliability is affected by the degree of estimation in the measurement process and by uncertainties inherent in what is being measured. Financial reporting may need to include narrative explanations about the underlying assumptions and uncertainties inherent in this process. Under certain circumstances, a properly explained estimate provides more meaningful information than no estimate at all.

A46. Concerning the proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources, the Board believes that both the quantity and the estimated Federal royalty share would be reliable. Thus, in this case, since the quantity of the estimated Federal royalty share can be reliably estimated and converted to monetary terms, the Board believes the estimated Federal royalty share of proved oil and lease condensate, NGPLs, and gas reserves should be recognized on the balance sheet.

A47. The EIA information on other than proved reserves is derived from sporadic and incomplete national assessments and annual submissions by oil and gas producers. This makes it particularly uncertain. In addition, since these reserves are not currently under lease, determining the royalty share may be misleading since it is a current value measure but the underlying asset may be restricted and production may never occur. For those resources that are not restricted, production may occur but the timing and amount of royalties are very uncertain. Thus, applying the same measurement technique to other than proved reserves may not result in a value that represents what it purports to represent. Thus, Federal oil and gas resources not yet in the 'proved reserves' category would not be recognized on the Federal balance sheet due to concerns regarding reliability of the proposed measure. However, information on these quantities would be provided as RSI.

Measurement Attributes Considered

A48. Concerning the dollar amount to be recognized for the estimated Federal royalty share of proved reserves, the Board considered various measurement attributes,[18] including the following:

A49. Historical cost (historical proceeds) – The amount of cash, or its equivalent, paid to acquire an asset, commonly adjusted after acquisition for amortization or other allocations. (SFAC 5, Par 67.a) 'Historical cost' was not a feasible option for valuing the oil and gas reserves because there is no 'historical exchange price' for the oil and gas reserves controlled by the Federal government.

A50. Fair value – When market transactions are available, fair value is the same as market value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. (FASB Statement of Financial Accounting Standards (SFAS) 157: *Fair Value Measurements*) Information needed to estimate fair value is not available as there are no current transactions between market participants involving the sale of the Federal royalty share for proved oil and lease condensate, NGPLs, and gas reserves. Nor are there current transactions between market participants for the sale of rights to comparable future revenue streams.

A51. Net realizable (settlement) value – The total non-discounted amount of cash, or its equivalent, into which an asset is expected to be converted in due course of business less direct costs, if any, necessary to make that conversion. (SFAC 5, Par 67.d) The 'net realizable value' (NRV) requires a reasonable estimate of future flows (receipts and costs) associated with converting assets to cash. However, the amount of the future flows of the Federal royalty share for proved oil & gas reserves cannot be reliably estimated for various reasons. The amount cannot be reliably estimated due to volatile fluctuations in the first purchase price for oil and wellhead price for gas. Reasons for these variations include:

a. The permitting process for exploration, development, and production activities.
b. The lessee's budget.
c. Other projects the lessee is focusing on.
d. The geological make-up of the earth.
e. The depth of the water or the depth of the wells for offshore wells.
f. The uncertainties of each well.
g. New discoveries.
h. Improved technology.
i. The economy and price volatility.
j. Production incentives provided by the Federal government.

[18] Measurement attribute – An attribute that can be quantified in monetary units with sufficient reliability. (Adapted from SFAC 5, *Recognition and Measurement in Financial Statements of Business Enterprises*, paragraph 65.)

A52. Present (or discounted) value of future cash flows – The present or discounted value of future cash inflows into which an asset is expected to be converted in due course of business less present values of cash outflows necessary to obtain those inflows. (SFAC 5, Par 67.e) An estimate of the ‘present (or discounted cash) value’ of the estimated Federal royalty share appeared to be most appropriate because the asset will be converted in future periods. However, the ‘present (or discounted cash) value’ attribute poses measurement challenges because:

a. The timing of future inflows is not reliably estimable.
b. The discount rate should be commensurate with the riskiness of the stream and each well might be viewed as having a unique level of risk.
c. Prices are subject to fluctuation, making the amount of future inflows volatile.

The timing cannot be reliably estimated because of the variable period of time from when a lease is signed until production begins (from 3 years to 20 years or more) and the variable period of time that a well will be productive. Thus, the estimated present value would be unreliable and, therefore, not cost-beneficial for valuing oil and gas reserves.

A53. Based on the above, the Board determined that none of the measurement attributes currently used in practice is a feasible measure of the estimated Federal royalty share for proved oil and lease condensate, NGPLs, and gas reserves. In addition the Board believes that assigning any one of the measurement attribute terms currently in use would only cause confusion once entities are required to apply the measurement attribute to the Federal estimated petroleum royalties. The Board believes that defining a measurement attribute in terms that are common to the oil and gas industry would be the best approach. Therefore, the Board proposes to use a regional average first purchase price for oil and lease condensate, a regional average first purchase price for NGPLs, and a regional average wellhead price for gas to value the Federal royalty share of proved oil and lease condensate, NGPLs, and gas reserves and referred to as Federal estimated petroleum royalties.

Valuation of the Federal Asset “Estimated Petroleum Royalties”

A54. The Board believes that the most relevant, reliable, and cost-beneficial measurement of “estimated petroleum royalties” would be obtained by using regional information. Regional estimated petroleum royalties would be calculated by multiplying the regional estimated quantity of proved reserves by the regional average first purchase price or regional average wellhead price and an effective regional average royalty rate. This calculation would provide the value of the “estimated petroleum royalties” for proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources for each region. The formulas to calculate regional values of estimated petroleum royalties are as follows:

For oil and lease condensate:

Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves X Regional Average First Purchase Price for Oil and Lease Condensate X Effective Regional Average Royalty Rate for Oil and Lease Condensate = Regional Estimated Petroleum Royalties for Oil and Lease Condensate

For natural gas plant liquids:

Regional Estimated Quantity of Proved NGPLs Reserves X Regional Average First Purchase Price for NGPLs X Effective Regional Average Royalty Rate for NGPLs = Regional Estimated Petroleum Royalties for NGPLs

For gas:

Regional Estimated Quantity of Proved Gas Reserves X Regional Average Wellhead Price for Gas X Effective Regional Average Royalty Rate for Gas = Regional Estimated Petroleum Royalties for Gas

A55. Proved reserves comprise crude oil, natural gas liquids (lease condensate and NGPLs), and natural gas.

A56. Crude oil exists in a liquid state; it may be described on the basis of its American Petroleum Industry (API) gravity as “light” (i.e., approximately 20 degrees to 50 degrees API) or “heavy” (i.e., generally less than 20 degrees API). Condensate is a very high-gravity (i.e., generally greater than 50 degrees API) liquid. NGPLs are those hydrocarbons in natural gas that are separated as liquids (byproducts) at natural gas processing plants, fractionating and cycling plants, and, in some instances, field facilities. Natural gas is a gaseous hydrocarbon resource.

A57. It is common for industry to count lease condensate reserves with their crude oil reserves. Lease condensate liquids generally are mixed in with crude oil and transported to petroleum refineries. For valuation purposes, their value is not much different than that for crude oil. Therefore, the Board believes oil and lease condensate should be combined in the process of calculating the Federal government’s estimated petroleum royalties and reported jointly in disclosures and RSI.

A58. NGPLs are extracted from natural gas, either at the production site or downstream at a natural gas processing plant. NGPLs include products like propane and butane. The market value for NGPLs is generally much lower than that for crude oil. In 2005, the average value of federal oil was $47 a barrel, and the average value for NGPLs was about $30 a barrel. (A difference of approximately $17 per barrel). The Board believes NGPLs should be separately valued in the process of calculating the Federal government’s estimated petroleum royalties. In addition, disclosures and RSI should distinguish NGPLs from other components.

A59. Because of the diversity between natural gas and crude oil, including the price and measurement metric, the Board believes natural gas should be separately valued in the process of calculating the Federal government's estimated petroleum royalties. Disclosures and RSI should distinguish natural gas from other oil and gas components.

A60. The Board believes this approach would provide conservative, representative regional values of estimated petroleum royalties without having to use proved reserve, price, and royalty rate information on a field-by-field[19] basis. The Board believes it would not be practicable to make calculations on a field by field basis. There are more than 60,000 leases maintained by the DOI with approximately 115,000 producing wells. In addition, the EIA maintains only the proved reserve information for each field, which it aggregates; while, the DOI maintains only the price and royalty rate information for each field.

Definition of Liability

A61. In the Elements ED, the proposed definition of a liability[20] is:

> "A liability is a present obligation[21] of the federal government to provide assets or services to another entity at a determinable date, when a specified event occurs, or on demand." A liability of the federal government has two essential characteristics. First, it constitutes a present obligation to provide assets or services to another entity. Second, the federal government and the other entity have an agreement or understanding as to when settlement of the obligation is to occur.[22]

Recognition Criteria

A62. Recognition criteria for all elements of accrual-basis financial statements, including liability, are discussed in paragraphs A39 and A40 of this document.

Valuation of the Offsetting Liability for the "Estimated Petroleum Royalties" Asset

A63. In this draft ED, the Board proposes that the federal government's estimated petroleum royalties be recognized as an asset on the balance sheet of the component entity that is responsible for collecting royalties. The asset's value would be based on the royalty share of the Federal oil and gas resources classified as "proved reserves." In addition to the royalties that the component

[19] Field: An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or by both. The area may include one lease, a portion of a lease, or a group of leases with one or more wells that have been approved as producible.
[20] See footnote 16 regarding the status of the Elements ED.
[21] The term *obligation* is used with its general meaning of a duty or responsibility to act in a certain way. It does not mean that an obligation of budgetary resources is required for a liability to exist in accounting or financial reporting or that a liability in accounting or financial reporting is required to exist for budgetary resources to be obligated.
[22] Elements ED, paragraphs 38 and 40.

entity collects on proved reserves that are produced, it also collects lease sale and rent revenue from federal government oil and gas leases. The component entity distributes nearly all of these proceeds to the general fund of the U.S. Treasury, other federal agencies, and states in accordance with legislated allocation formulas. The component entity also receives a very small portion of the revenue collected to fund its operations. The amount used to fund its operations is legislated by Congress as part of the component entity's annual appropriation. For example, the amount received by the component entity was approximately one percent (1%) of annual revenues collected in 2005.

A64. The Board considered and agreed that an offsetting liability should be recognized in conjunction with the recognition of an asset for estimated petroleum royalties. The Board believes an offsetting liability should be recognized because nearly all of the revenue from royalties, lease sales, and rent are ultimately distributed to the general fund of the U.S. Treasury, other federal agencies, and the states. As the proceeds are distributed, the liability would be reduced. In addition, upon consolidation, the portion of the liability related to other federal agencies and the general fund of the U.S. Treasury would be eliminated so that the balance sheet for the government as a whole reports only the liability for amounts allocated to non-federal entities.

A65. The Board believes that if a liability was not established, the component entity's and the federal government's net position would be overstated.

Regional Estimated Quantity of Proved Reserves

A66. The Board proposes that the regional estimates of proved oil and lease condensate reserves, proved NGPL reserves, and proved gas reserves from Federal oil and gas resources be used to calculate and value the Federal government's "estimated petroleum royalties" to be capitalized. The source for the regional estimates for these proved reserves would be the EIA, based on the required field-by-field filings by oil and gas operators.

A67. The EIA defines proved reserves as those volumes of crude oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves, however, are not quantities that can be counted; nor, are they direct measurements. They are estimates. Proved oil and lease condensate reserves are estimated in barrels at 60 degrees Fahrenheit. Proved NGPL reserves are estimated in barrels at 60 degrees Fahrenheit. Proved gas reserves are estimated in thousands of cubic feet (Mcf) at 14.73 PSIA and 60 degrees Fahrenheit.

A68. EIA's proved reserves estimates are based on data filed by: 1) large, intermediate, and a select group of small operators of oil and gas wells; and, 2) operators of all natural gas processing plants. The EIA requires the top 600 operators to submit a direct report of the proved reserves they carry for each field as of December 31. The reports are required to be submitted by April 15 of the year following the December 31 cut-off date. The EIA checks and edits all of the reports at the field level and that number would exceed 20,000 operator field reports. On all the checks and edit steps, the EIA relies on its own engineering staff. In addition, the EIA staff independently checks about 20 fields a year. This can be described as an audit procedure performed by the EIA staff. The fields are selected either because they are new or there is something that might attract attention to the EIA about the field. The EIA points out significant errors or misinterpretations to the operators for correction.

A69. The EIA has been reviewing the domestic numbers of proved reserves estimates independently for more than 25 years. The EIA observes that if one looks at an individual field you almost always find it to be within professional competence; and, if you look at an aggregate of a number of fields those numbers are even more reliable. The EIA issues a report containing aggregated volume information for crude oil and lease condensate, natural gas plant liquids, and natural gas. The report is issued in the month of September containing volume information as of December 31 of the preceding calendar year. The information contained in the report has a very high probability that there is at least the physical volume that is estimated.

A70. Estimated proved reserves are calculated in the following manner:[23]
Published Proved Reserves at End of Previous Report Year
+ Adjustments
+ Revision Increase
- (Less) Revision Decreases
- Sales
+ Acquisitions
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
- Report Year Production
= Published Proved Reserves at End of Report Year

A71. The published reserves estimates include an additional term— adjustments— calculated by the EIA, which preserves an exact annual reserves balance. Adjustments are the annual changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories. They result from the survey and statistical estimation methods employed. For example, variations caused by changes in the operator frame, different random samples, different timing of reporting, incorrectly reported data, or imputations for missing or unreported reserve changes can contribute to adjustment.

A72. The proved reserve information provided by the operators to the EIA is generally the same information the operators are required to send to the U.S. Securities and Exchange Commission (SEC) in their annual report for oil and gas producing activities. The SEC receives approximately 14,000 financial statement submissions on a yearly basis, which include financial statements from operators of oil and gas wells. Each submission is reviewed on a

[23] The source of information used to describe the calculation of estimated proved reserves is the EIA-23, *Annual Survey of Domestic Oil and Gas* instructions.

rotational basis every three years based on internal selection policies and criteria.

Alternative Quantity Information

A73. The Cambridge Energy Research Associates (CERA) developed a report on Oil and Gas Reserves Disclosure. The focus of the CERA report was that the 27-year-old U.S. system for measuring and reporting oil and gas reserves is no longer keeping pace with a changing, increasingly global industry and, as a result, falls short of accurately describing industry and individual companies' reserves. It was suggested by a Board member that the FASAB proposed accounting standards for oil and gas resources request comments on the possibility of estimating petroleum royalties using a probabilistic method of measuring proved reserves as suggested in the CERA report.

A74. The Board's proposal is to use a single best estimate of recovering reserves based on known geological, engineering, and economic data, and this approach is known in the oil and gas industry as the deterministic method. In contrast, the probabilistic method of estimation uses the known geological, engineering, and economic data to generate a range of estimates and their associated probabilities of recovering reserves. Using the probabilistic method, identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. The Society of Petroleum Engineers, the World Petroleum Congresses, and the American Association of Petroleum Geologists agree:

a. There should be at least a 90 percent probability that the quantities of proved reserves actually recovered will equal or exceed the estimate.
b. There should be at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.
c. There should be at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

A75. The Board proposes using only the "proved reserves" to calculate the estimated petroleum royalties of the Federal government for capitalization on the balance sheet. In addition, RSI would be displayed for other oil and gas resources.

A76. Information pertaining to "unproved probable reserves" or "unproved possible reserves" is not required to be submitted to any Federal government entity and no Federal entity has the information. Mandating that internal decision-making information about these two types of reserves be reported by producers and operators would impose an additional reporting requirement on these non-Federal entities.

A77. The MMS does study and report information about unproved reserves as a whole, i.e., without any delineation between "unproved probable reserves" and "unproved possible reserves." In addition, the information it reports about unproved reserves is not current. That is, up-to-date information is not available. For example, the most current information about the Gulf of Mexico region reserves was issued by the MMS in November 2006 for the period ending December 31, 2003. Information about the Pacific region is even less current; and, information about the Alaska region is not currently reported. In addition, there is no information available for onshore oil and gas reserves.

A78. In summary, the EIA's estimate of proved reserves is the only current and complete estimate of reserves the Federal government has. Developing a probabilistic model, acquiring the information from producers, and assessing reserves not under lease on a routine basis would be burdensome and would not be cost-beneficial. Therefore, the Board believes asset recognition should be based on proved reserves using the deterministic method.

Regional Average First Purchase and Regional Average Wellhead Price

A79. There are two prices used to calculate the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves.

A80. The first price is "first purchase price" and, for purposes of these standards, is used in the crude oil and lease condensate, and NGPLs environments. A "first purchase" constitutes a transfer of ownership during or immediately after the physical removal of the crude oil and lease condensate or NGPLs from a production property for the first time. The proposed regional average "first purchase price" would be calculated by dividing the total regional sales value of oil and lease condensate or NGPLs produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months by the total regional sales volume of oil and lease condensate or NGPLs produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months. All types of crude oil streams and gravity bands are aggregated for the oil and lease condensate calculation. For example, if the total financial sales value for oil and lease condensate in a region was $12,762,548,440 and the total sales volume in the associated region was 666,108,296 barrels of oil and lease condensate, the average first purchase price for the region would be $19.16 per barrel. This information is available to the MMS. Sales value and the sales volume information is provided to the MMS by oil producers on a monthly basis.

A81. The second price is "wellhead price" used in the gas environment. The wellhead price is the value of the purchased gas at the mouth of the well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. The regional average wellhead price for gas would be calculated by dividing the total regional sales value of gas produced from Federal oil and gas resources in each region for the preceding twelve (12) months by the total regional sales volume of gas produced from Federal oil and gas resources in each associated region in the preceding twelve (12) months. For example, if the total financial sales value for gas in a region was $18,824,102,982 and the total sales volume in the associated region was 6,789,523,253 Mcf of gas, the average wellhead price for the region would be $2.77 per thousand cubic feet. This information is available to the MMS. Sales value and the sales volume information is provided to the MMS by gas producers on a monthly basis.

A82. The Board considered using market prices as of the end of the reporting period. However, the price in a specific market is not necessarily representative of the specific fields leased from the Federal government. In addition, the market price used in the spot market to value gas includes transportation charges. Producers do not pay royalties on transportation costs. Therefore, using the market price in the formula to calculate the value of federal petroleum royalties would cause the value to be inflated. In addition, the MMS sales volume and sales value information is more timely and more readily available.

Effective Regional Average Royalty Rate

A83. Royalty rate is a proportionate interest in the production value of mineral deposits due the lessor from the lessee in accordance with a lease agreement. For many years, the Federal government made oil and gas resources available to developers under the terms of the Mining Law of 1872, which offered properties on a noncompetitive basis for flat, per-acre fees. The current Federal royalty program originated in the Minerals Leasing Act of 1920. Later, the Acquired Lands Act of 1947 extended the leasing authority of the 1920 Act over lands in the public domain to include areas that the Federal government acquired from states and individuals. The OCS Lands Act of 1953 revised the oil and gas leasing program to make offshore leases available through competitive auctions. The most recent major changes to the program came with the Federal Onshore Oil and Gas Leasing Reform Act of 1987. The Act requires that all public lands available for oil and gas leasing be offered first by competitive leasing. Noncompetitive oil and gas leases may be issued only after the lands have been offered competitively at an oral auction and a bid was not received. Those basic laws establish procedures for leasing public lands to developers, collecting compensation from the developers in the form of initial payments and royalties on subsequent production, and disbursing the receipts to various government accounts and to the states.

A84. While the royalty rate is based on the lease agreement, the Secretary of the DOI may, upon application from a lease-holder, reduce the royalty rate for good cause. Examples where rates have been reduced have been operating conditions that caused costs to be extraordinarily high and where a well is approaching the end of its production life. Sometimes the reductions are for the remaining lease term, but more often they are for some limited period of time. Paragraphs A85 through A100 summarize possible royalty rates. Using an effective royalty rate is a means of adjusting the asset's value based on experience with reduced royalties.

Royalty Rate – Federal Onshore Leases

A85. Oral auctions of all oil and gas leases are conducted by most BLM State Offices not less than quarterly when parcels are available. A Notice of Competitive Lease Sale, which lists lease parcels to be offered at the auction, are published by each BLM State Office at least 45 days before the auction is held. Lease stipulations applicable to each parcel are specified in the sale notice. Lands included In the sale notice come from three sources:

a. Existing leases that have expired, terminated, or been cancelled or relinquished;
b. Parcels identified by informal expressions of interest from the public or by the BLM for management reasons; or
c. Lands included in offers filed for noncompetitive leases.

A86. Royalty rates are assigned for competitive leases in the following manner:

a. Leases issued under the Mineral Leasing Act of 1920 (prior to December 23, 1987): oil royalty assessed on production amount ranges from 12.5 percent to 25 percent; gas royalty assessed on production amount ranges from 12.5 percent to 16.67 percent.
b. Leases issued after December 23, 1987: flat rate of 12.5 percent in amount (dollars) or value of production.

A87. Royalty rates for noncompetitive leases are 12.5 percent of the amount or value of production.

A88. Royalty rates are assigned for the National Petroleum Reserve for Alaska Leases at 16.67 percent.

Royalty Rate – Federal Offshore Leases

A89. The MMS Director publishes the notice of lease sale in the Federal Register. The publication must be at least 30 days prior to the date of the sale. The notice contains or references a description of the areas to be offered for lease and any stipulations, the royalty rate, terms and conditions of the sale.

A90. The OCS Lands Act, 43 U.S.C. 1337, as amended by the OCS Deep Water Royalty Relief Act (DWRRA), Public Law 104-58, authorizes the MMS to grant royalty relief. Royalty relief is the reduction, modification, or elimination of any royalty to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. Some of the royalty-free production might not have occurred absent the royalty relief incentive. Therefore, not all of the nominal royalties waived on actual production in the presence of royalty relief may actually be foregone. To the extent that such incremental projects pay royalties, some or all of those royalties serve to reduce the aggregate amount of foregone royalties on other projects. In addition, the royalty relief program also affects the bonus bid amounts. That is, bonus bid amounts are larger on lease sales offering royalty relief. So, to a certain extent, the bonus bid amounts ahead of production compensate for the future relief.

A91. Royalty relief has two thresholds, price and quantity. Depending on when a lease sale took place determines the effective price threshold and quantity threshold for each lease authorized for royalty relief. If prices rise above a threshold (base price) for crude oil or natural gas, set by statute, full royalties must be paid. For quantity thresholds, statutes authorize the MMS to grant royalty relief in three situations:

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

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

c. Under 43 U.S.C. 1337(a)(3)(C), it may suspend royalties for designated volumes of new production from any lease if:
(1) The lease is in deep water (water at least 200 meters deep);
(2) The lease is in designated areas of the GOM (west of 87 degrees, 30 minutes West longitude);
(3) The lease was acquired in a lease sale held before the DWRRA (before November 28, 1995);
(4) That DOI finds that new production would not be economical without royalty relief; and
(5) The lease is on a field that did not produce before enactment of the DWRRA, or if a project is proposed to significantly expand production under a Development Operations Coordination Document (DOCD) or a supplementary DOCD, that MMS approved after November 28, 1995.

A92. A royalty and remittance report, which contains the reported sales value, reported sales volume, and other related production information is due the last day of the month following the month the product was sold or removed from the lease, in accordance with proscribed legislation.

A93. At the end of the calendar year, if it is found through an audit that an operator has exceeded either one of the thresholds, the operator must:

a. 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 Sec. 218.54 of this chapter) by March 31 of the current calendar year, and
b. Pay royalties on all oil production in the current year.

A94. As a result of exceeding either threshold, all royalty relief must be paid and would no longer be considered royalty relief. In addition, in the succeeding year, while the operator must pay all royalties during the year, the operator may be eligible for royalty relief for the year if the operator complies with all requirements of the lease in accordance with royalty relief. In this latter case, the appropriate amount of royalties would be refunded to the operator.

A95. Tracts are offered for lease by competitive sealed bidding. Each lease bid must include a payment for one-fifth of the bonus bid amount. The payment will be invested in public securities and accrue interest. Interest accrued for the successful bid will accrue to the Government.

A96. The lease will not be executed with the successful bidder until payment of the remaining four-fifths bonus bid amount and the first year’s rental payment is received. Failure to remit payment within the time-frame specified will result in forfeiture of the one-fifth bonus bid amount. The one-fifth bonus bid amount and any interest accrued shall be refunded on high bids subsequently rejected. Bonus checks submitted with bids other than the highest valid bid shall be returned to respective bidders after bids are opened, recorded, and ranked.

A97. Royalty payments are due at the end of the month following the month during which the oil and gas is produced and sold except when the last day of the month falls on a weekend or holiday. In such cases, payments are due on the first business day of the succeeding month or the business day following the holiday.

A98. For leases not under the DWRRA, the royalty rate is set for each sale area in its Final Notice of Sale and may be:

a. 12.5 percent for water depths greater than 400 meters or 16.67 percent for water depths less than 400 meters.
b. Sliding scale (12.5 percent-65 percent) based on average of all production.
c. Step-scale which increases by steps as production increases.
d. Flat rate of 33.33 percent.
e. Net profit share, which require royalty only after certain expenditures are recovered.
f. Royalty suspension (variable according to water depth for deep water royalty relief and depth of well for shallow water deep gas royalty relief) followed by royalty rates under 1. above (i.e. 12.5 percent for water depths greater than 400 meters or 16.67 percent for water depths less than 400 meters).

A99. Leases Under Deepwater Royalty Relief Act. Certain Gulf of Mexico (GOM) deep water leases issued under DWRRA between November 28,1995 and November 28, 2000 receive royalty suspensions based on the following criteria:

a. Leases in fields located in between 200 and 400 meters of water do not pay royalties until 17.5 million barrels of oil equivalent (MMBOE) have been produced from the field.
b. Leases in fields located in between 400 and 800 meters of water do not pay royalties until 52.5 MMBOE have been produced from the field.
c. *Leases in fields located in deeper than 800 meters of water do not pay royalties until 87.5 MMBOE have been produced from the field.*

A100. GOM deep water leases issued under DWRRA beginning in 2002 receive royalty suspensions based on the following criteria:

a. Leases in fields located in between 400 and 800 meters of water do not pay royalties until 5 MMBOE have been produced from the field.
b. Leases in fields located in between 800 and 1,600 meters of water do not pay royalties until 9 MMBOE have been produced from the field.
c. Leases in fields located in deeper than 1,600 meters of water do not pay royalties until 12 MMBOE have been produced from the field.

A101. Because the Board believes using proved reserve, pricing and royalty information from each field would not be practicable, a meaningful and relevant royalty rate was needed in calculating the representative value of the Federal government's estimated petroleum royalties. The Board, therefore, proposes that effective regional average royalty rates for oil and lease condensate, NGPLs, and gas be used in calculating the Federal government's estimated petroleum royalties. Members believe using the effective regional average royalty rates, in contrast to a statutory rate, would be more representative and meaningful because of the varying degrees of royalty rates for onshore and offshore leases and the royalty relief program for offshore leases. The effect of calculating the rate in this manner is to reduce the asset value based on the royalty relief experience during the preceding twelve months. The Board believes this approach is a reasonable means to avoid overstating the asset in light of the variability in royalty relief in the future.

A102. The effective regional average royalty rate for oil and lease condensate is calculated by dividing the royalty value (royalties) earned on all of the oil and lease condensate reserves that were produced from Federal oil and gas resources in each associated region for the preceding twelve (12) months by the sales value of that production for the preceding twelve (12) months. For example, if the total royalties earned on the produced reserves from the associated region was $4,406,985,439, and the total sales value for oil from a region was $31,586,651,422, the effective regional average royalty rate would be 13.952 percent. This information is available to the MMS. Sales value and the royalty information is provided to the MMS by oil and gas producers on a monthly basis.

A103. The effective regional average royalty rate for NGPLs would be calculated by dividing the royalty value (royalties) earned on the NGPL reserves produced for each associated region for the preceding twelve (12) months by the total sales value of that production for the preceding twelve (12) months.

A104. The effective regional average royalty rate for gas would be calculated by dividing the royalty value (royalties) earned on the gas reserves produced for each associated region for the preceding twelve (12) months by the total sales value of that production for the preceding twelve (12) months.

Calculating the Federal Government's "Estimated Petroleum Royalties"

A105. Using the described components in the formula, the Federal government's estimated petroleum royalties would be calculated in the following manner.

A106. The summarized quantity of proved oil and lease condensate reserves from oil and gas fields that are leased from the Federal government and included in the EIA survey for a region should be multiplied by the associated regional average first purchase price for oil and lease condensate. This calculation will equal the regional value of proved oil and lease condensate reserves from oil fields that are leased from the Federal government.

A107. Each regional value of proved oil and lease condensate reserves from oil fields that are leased from the Federal government would be multiplied by the associated effective regional average royalty rate. This calculation will equal the estimated petroleum royalties for oil and lease condensate from oil fields that are leased from the Federal government for each region.

A108. The summarized quantity of proved NGPL reserves for each region from gas fields that are leased from the Federal government and included in the EIA survey would be multiplied by the associated regional average first purchase price for NGPLs. This calculation will equal the value of proved NGPL reserves for each region from gas fields that are leased from the Federal government.

A109. Each regional value of NGPL reserves from gas fields that are leased from the Federal government would be multiplied by the associated effective regional average royalty rate. This calculation will equal the estimated petroleum royalties for NGPLs from gas fields that are leased from the Federal government for each region.

A110. The summarized quantity of proved gas reserves for each region from gas fields that are leased from the Federal government and included in the EIA survey would be multiplied by the associated regional average wellhead price for gas. This calculation will equal the value of proved gas reserves for each region from gas fields that are leased from the Federal government.

A111. Each regional value of proved gas reserves from gas fields that are leased from the Federal government would be multiplied by the associated effective regional average royalty rate for gas. This calculation will equal the estimated petroleum royalties from gas fields that are leased from the Federal government for each region.

A112. The regional values of estimated petroleum royalties for oil and lease condensate reserves from oil and gas fields that are leased from the Federal government, the regional values of estimated petroleum royalties for NGPLs reserves from gas fields that are leased from the Federal government, and the regional values of estimated petroleum royalties from gas fields that are leased from the Federal government would be added together. This calculation would provide the value of the Federal government's estimated petroleum royalties from proved reserves to be capitalized.

A113. The Board believes using the described components in the formula for calculating the regional estimated petroleum royalties would provide a representative value of the estimated proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources for the reporting period. The information provided for each component is verifiable and reliable. In addition, it is consistent and relevant. That is, it is aggregated and calculated at the regional level, it is based on recent oil and gas production activities, and it incorporates recent economic experience including royalty relief experience.

Future Rights to Royalty Stream Identified for Sale

A114. When rights to a future royalty stream are identified to be sold, the value of those rights should be disclosed as "future royalty rights identified for sale." Future royalty rights identified for sale should not be revalued or reclassified to a different asset category on the balance sheet because the point in time for the sale of the future royalty rights may be uncertain and the identified fields may continue to produce oil and/or gas and generate royalties. These two factors make it difficult to establish and maintain valuation information in advance of the sale. No gain or loss on the future royalty rights identified for sale should be calculated since the rights for sale are only disclosed and are not revalued and reclassified to a different asset category on the balance sheet. Disclosure of the approximate value at the balance sheet date alerts the reader to the pending sale and the potential value of the asset to be sold.

A115. The value of the disclosed future royalty rights identified for sale is based on the estimated quantity of proved reserves to be involved in the sale for a specific field; the first purchase price for oil and lease condensate, the first purchase price for NGPLs, or the wellhead price for gas for a specific field for which future royalty rights were identified for sale; and the royalty rate for a specific field identified for sale. Because the fields are known, this provides a more field specific value for the rights identified to be sold, instead of using an effective average royalty rate and an average unit price.

A116. At the time the future royalty rights identified for sale are sold, the calculated value of the future royalty rights sold would be calculated based on the quantity of proved reserves involved in the sale for a specific field; the first purchase price for oil and lease condensate, the first purchase for NGPLs, or the wellhead price for gas pertaining to a field at the time of sale; and the royalty rate for a specific field. An amount equal to this calculated value would be removed from the value of estimated petroleum royalties at the time of the sale. This calculation is used to reduce the estimated petroleum royalties since the values of a specific field are known and the value of the future royalty rights sold can be more accurately calculated, which would provide a more realistic gain or loss on the sale. In addition, the liability for revenue distributions to others should be adjusted by the amount of the gain or loss on the sale, if any, and reduced when the sale proceeds are distributed.

Disclosures

A117. The Board proposes that various types and amounts of information be disclosed in the notes or provided as RSI. For example, one proposed disclosure would require a narrative describing and a display showing earned revenue reported by category for the reporting period. That is, royalty revenue earned for oil and lease condensate, royalty revenue earned for NGPLs, royalty revenue earned for gas, earned rent revenue, earned bonus bid revenue for leases, and total revenue. The proposed RSI includes sales volume, the sales value, the royalty revenue earned, and the estimated value for royalty relief for oil and lease condensate, NGPLs, and gas produced from Federal oil and gas resources for the reporting period on a regional basis. Proposed RSI also includes a narrative describing and a display showing detailed historical information for the preceding ten calendar years. (See paragraphs 30 through 34 and Appendix D for a complete review of all proposed disclosures and RSI requirements.)

A118. Although the Board agreed that the proposed information be disclosed in the notes or provided as RSI, there are some Board members who are concerned about the type and level of information being proposed as disclosures or RSI. Some of the proposed information is available through reports other than financial reports. Therefore, the Board has posed a question in the Request for Comments section of this document, question number Q3, asking reviewers of this document for feedback on the value of the proposed information being presented in financial statements. Specifically, the Board is asking that reviewers describe how the types and levels of information would be used, if and how the information would be used for assessing the financial position of the Federal government, and how the information would be useful in decision-making. The Board also asks if there is information which is not proposed as a disclosure or RSI but would be useful for assessing the financial position of the Federal government and in decision-making.

Alternative View

A119. Individual members sometimes choose to express an alternative view when they disagree with the Board's majority position on one or more points in a proposed standard. The alternative view would discuss the precise point or points of disagreement with the majority position and the reasons therefore. The ideas, opinions and statements presented in the alternative view are those of the individual member alone. However, the individual member's view may contain general or other statements that may not conflict with the majority position, and in fact may be shared by other members. The following material was prepared by Board member Donald B. Marron.

Fair Value Is the Appropriate Basis for Valuing Oil and Gas Resources

A120. Financial accounting is moving toward greater use of fair value estimates for financial assets and liabilities for private sector reporting entities.[24] Fair value is the price that would be received for an asset or paid to transfer a liability in a transaction between market participants at the measurement date. In general, fair value measures provide relevant, timely, and relatively accurate valuations. The desirable attributes of fair values are equally appropriate to valuations of physical resources; where possible, the federal balance sheet should report the fair value of the nation's natural resources, including oil and gas. Establishing appropriate values for oil and gas is particularly important because that methodology may set a precedent for how other federal natural resources, such as coal and timber, are valued on the federal balance sheet.

A121. A standard for recognizing federal oil and gas resources as an asset must distinguish two categories of federal holdings: proved reserves and all other. For proved reserves, the fair value to the federal government is the present value of expected contract royalties.[25] For all other gas and oil holdings, including unproved resources that have not been offered for lease and resources that might never be tapped, fair value is the present value of expected bonuses, rents, and royalty payments.[26] But for both types of holdings, fair value is the appropriate valuation.

[24] FASB SFAS 159, "The Fair Value Option for Financial Assets and Financial Liabilities."

[25] For an analysis of how reserves should be measured, see Cambridge Energy Research Associates, *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosure* (Cambridge, Mass., February 2005); statement of Bala G. Dharan, Professor of Accounting, Rice University, "Improving the Relevance and Reliability of Oil and Gas Reserves Disclosures," before the House Committee on Financial Services, July 21, 2004; and Society of Petroleum Engineers, "Why a Universal Language for Evaluating Reserves Is Needed" (white paper, February 27, 2006), available at www.spe.org/web/org/Resources_White_Paper.pdf.

[26] Some federal oil and gas resources are currently restricted from development by law. This alternative view does not take a position on whether to report those resources on the balance sheet.

Shortcomings of the Majority Proposal

A122. The Board proposal has two shortcomings. First, the Board proposes to recognize only proved reserves, even though other properties that the Federal government controls may have significant value. The value of proved reserves is thus an underestimate of the resources available from federal lands and offshore areas. Second, the Board proposes to value proved reserves using a means other than fair value. Experience with resource prices indicates that the estimated value of proved reserves, using the Board's approach, will typically be overstated, perhaps significantly.

A123. The exposure draft posits that information needed to estimate fair value is not available (paragraph A50). However, several methods are available for estimating the fair value of federal oil and gas reserves, including the value of comparable private market transactions and discounted cash flow valuations of the government's projected receipts from leases on federal lands. Some methods, such as discounted cash flows, appear to be more suitable for arriving at the fair value of proved reserves, while the value of comparable private market transactions may be more suitable for determining the fair value of other holdings.

A124. FASAB proposes to value federal oil and gas resources on the basis of expected federal royalty receipts on current proved reserves. The formula used to calculate those receipts would be: estimated quantity of proved reserves multiplied by the average price at the wellhead multiplied by the average royalty rate (paragraphs 16 through 19).

A125. FASAB's proposed valuation methodology for the federal government's future stream of royalty receipts is a departure from fair value and ignores the available information about the market value of those resources. First, the proposed valuation fails to discount the stream of future royalty payments to the government to reflect the time value of money and thus overstates the present value of those future receipts. The exposure draft acknowledges in principle the desirability of discounting future streams of payments but states that the uncertainty surrounding the average life of a lease, production schedules, and future prices is too great to project cash flows reliably (paragraph A52). The standard's approach to valuation, however, does not address that uncertainty or risk. The aggregate cash flow stream for each region could be estimated from reserve levels and historic and forecast levels of economic aggregates such as oil prices and production rates.[27] Second, the valuation relies on current prices and hence ignores expected changes in energy prices over time.

A126. Under some circumstances, these two flaws in the majority's valuation approach—the lack of discounting and the use of current rather than future prices—will tend to offset each other. In particular, the majority's valuation method would be reasonably accurate if future oil and gas prices are expected

[27] In general, production rates from developed fields are relatively stable, varying only little with current prices. Government rules and standard engineering practices specify production rates and development paths for a field that will maximize total output over time.

to increase over time at a rate equal to the appropriate risk-adjusted discount rate. Such a relationship between prices and the discount rate could occur, but only if resource prices follow one well-known theoretical model of resource prices, the Hotelling model. Unfortunately, current oil and gas markets do not appear to satisfy the specific conditions that are assumed in the Hotelling model.[28] Moreover, the Hotelling model has performed poorly in explaining the actual time path of resource prices.[29] It is therefore unlikely that the majority approach—which ignores both discounting and the potential for resource prices to change in the future—will, by happenstance, provide valuation estimates that approximate fair value. A more accurate assessment of the value of oil and gas reserves thus requires projecting the nominal value of future oil and gas royalties and discounting those royalties to determine the fair value of the resources.

Fair Value Measures

A127. When market transactions are available, fair value is the same as market value. In the absence of active trading markets that would provide a current quote for identical assets, the Financial Accounting Standards Board has proposed a hierarchy of fair value measurement methodologies.[30] Estimates can be based on observable prices from transactions involving comparable assets. In the absence of comparable prices, reporters may estimate fair value by converting future cash flows to present values by discounting. It will be up to preparers (and then the auditors) to decide how to best estimate fair value.

Private Market Transactions

A128. Prices from private market transactions have the potential to serve as fair value estimates of oil and gas reserves.[31] Oil and gas producers regularly exchange individual properties and leases that include proved reserves, reservoirs that

[28] The Hotelling model implies that the net price (sales price less extraction costs) of an exhaustible resource, such as oil and natural gas, will increase over time at the rate of interest (if this relationship did not hold, producers would have an incentive to increase or decrease their current production in such a way that would equate the growth of net prices with the rate of interest). This model relies on numerous assumptions—for example, that extraction costs are constant, there is no market uncertainty and market participants have perfect foresight, the amount of the resource is fixed in supply, and markets are perfectly competitive—that do not apply in current oil and gas markets. Moreover, even if these conditions did hold, the model would imply that sales prices would grow more slowly than the rate of interest as long as extraction costs are significant.

[29] Differences between the Hotelling valuation and reserve prices can be significant and persist over long periods. For example, one analysis estimates that the Hotelling valuation was more than double the estimated reserve price in 2003. M.A. Adelman and G.C. Watkins, *Oil and Natural Gas Reserve Prices: Addendum to CEEPR WP 03-016 Including Results for 2003 and Revisions to 2001,* Working Paper No. 20015-013 (Cambridge Mass.: MIT Center for Energy and Environmental Policy Research, March 2005), available at http://web.mit.edu/ceepr/www/2005-013.pdf.

[30] Financial Accounting Standards Board, Statement of Financial Accounting Standards No. 157, “Fair Value Measurements.”

[31] This is one of several methods approved for use by the Department of the Interior; see Bureau of Land Management, *Economic Evaluation of Oil & Gas Properties*, available at www.blm.gov/nhp/efoia/wo/handbook/h3070-2.html.

have been found and are being developed, or merely “probable” reserves. The market values for those properties reflect the present discounted value of future earnings—including the cost and levels of production over time, expected changes in oil and gas prices, and discount rates that encompass appropriate risks. Those transactions totaled over $600 billion for existing oil and gas fields between 1979 and 2003.[32]

A129. Sales of oil and gas reserves indicate that energy resources in the ground are worth much less than the wellhead prices because the reserves cannot be produced and delivered to a buyer immediately. Expectations about production costs and future wellhead price changes also affect valuations. On average, proved oil and gas reserves have sold for only about 20-25 percent and 30-40 percent of their respective wellhead prices for the 1991-2001 period. About 15 percent of the change in oil prices at the wellhead is reflected in proved reserve prices.[33]

Discounted Cash Flow Models

A130. Discounting the government’s expected receipts from bonus bids, royalty payments, and rents is an alternative approach to estimating fair market values when comparable transactions are unavailable. That approach has been used by the Department of the Interior. Discounted cash flow models require estimates of risk-adjusted discount rates, future prices, and production flows.[34] Risk-adjusted discount rates rather than Treasury rates are appropriate because of uncertainty about future prices and production flows.[35] Texas

[32] See James L. Smith, *Petroleum Property Valuations*, Working Paper No. 2003-11 (Cambridge, Mass.: MIT Center for Energy & Environmental Policy Research, June 2, 2003), available at http://web.mit.edu/ceepr/www/2003-011.pdf. (Note: this paper was published as James L. Smith, “Petroleum Property Valuation,” *Encyclopedia of Energy*, Cutler J. Cleveland, ed., Academic Press (March 2004)).

[33] Transaction prices for oil and gas reserves tend to be less volatile than wellhead prices. See Smith (June 2, 2003), pp. 6-8 and Figure 3. For natural gas, about 10 percent of the change in field prices would be reflected in proved reserve prices. See M.A. Adelman and G.C. Watkins, *Oil and Natural Gas Reserve Prices: Addendum to CEEPR WP 03-016 Including Results for 2003 and Revisions to 2001*, Working Paper No. 2005-013 (Cambridge, Mass.: MIT Center for Energy & Environmental Policy Research, March 2005), available at http://web.mit.edu/ceepr/www/2005-013.pdf. For a detailed discussion of the data sources see, M.A. Adelman and G.C. Watkins, *Oil and Natural Gas Reserve Prices: 1982-2002: Implications for Depletion and Investment Cost*, Working Paper No. 2003-016 (Cambridge, Mass.: MIT Center for Energy & Environmental Policy Research, October 2003), pp. 11-1, available at http://web.mit.edu/ceepr/www/2003-016.pdf.

[34] An alternative approach would be to use a (real) options-pricing model. That approach, which requires an estimate of the market price of reserves and its volatility, recognizes that management can decide whether and when to develop an energy field and at what production rate. These strategic decisions affect the risk of production cash flows over time, which means that a constant risk-adjusted rate is not appropriate. Options-pricing methods provide a systematic method for discounting cash flows when risks change over time. See Smith (June 2, 2003), p. 11

[35] See Smith (June 2, 2003), pp. 3-4. For an analysis of the relevance of market risk to the government, see Congressional Budget Office, *Estimating the Value of Subsidies for Federal Loans and Loan Guarantees* (August 2004), available at www.cbo.gov/ftpdocs/57xx/doc5751/08-19-CreditSubsidies.pdf.

assesses property taxes on the fair value of oil and gas reserves and provides guidance on acceptable risk-adjusted discount rates of future cash flows.[36]

A131. The expected future prices of oil and gas can be observed in the futures market.[37] While most trading is for contracts for delivery in less than a year, contracts for delivery in December 2012 are also currently available.[38] Prices for the period beyond 2012 could be projected using economic models.

A132. To project flows, the Energy Information Administration and others generally assume in their forecasts that the ratio of production to proved reserves will remain constant, which is consistent with historical data. Thus, the current production to reserve ratio can be used to represent a constant rate of decline for future production.

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36 For a discussion of Texas's guidelines, see www.window.state.tx.us/taxinfo/proptax/ogman/index.html.

37 Researchers have found that spot market prices are much more volatile than longer term futures contracts. See Miguel Herce, John E. Parsons and Robert C. Ready, *Using Futures Prices to Filter Short-Term Volatility and Recover a Latent, Long-Term Price Series for Oil,* Working Paper No. 2006-005 (Cambridge, Mass: MIT Center for Energy and Environmental Policy Research, April 2006), available at http://web.mit.edu/ceepr/www/2006-005.pdf.

38 Oil and natural gas futures trade on the New York Mercantile Exchange; see www.nymex.com/lsco_fut_csf.aspx?product=CL and www.nymex.com/ng_fut_csf.aspx?product=NG.

APPENDIX B: LIST OF ABBREVIATIONS

API	American Petroleum Industry
Bbl	Barrels
BLM	Bureau of Land Management
Btu	British Thermal Unit
CERA	Cambridge Energy Research Associates
CFR	Consolidated Financial Report
CFR	Code of Federal Regulations
DOI	Department of Interior
DWRRA	Deep Water Royalty Relief Act
ED	Exposure Draft
EIA	Energy Information Administration
FASAB	Federal Accounting Standards Advisory Board
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
GOM	Gulf of Mexico
Mcf	Thousand Cubic Feet
MMBOE	Million Barrels of Oil Equivalent
MMS	Minerals Management Service
OCS	Outer Continental Shelf
NEPA	National Environmental Policy Act
NGPLs	Natural Gas Plant Liquids
PSIA	Pounds Per Square Inch Absolute
RSI	Required Supplementary Information
SEC	Securities and Exchange Commission
SFAC	Statement of Financial Accounting Concepts
SFFAC	Statement of Federal Financial Accounting Concepts
SFAS	Statement of Financial Accounting Standards
SFFAS	Statement of Federal Financial Accounting Standards
U.S.	United States
USGS	U.S. Geological Survey

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APPENDIX C: PRO FORMA TRANSACTIONS AND FINANCIAL STATEMENTS

PLEASE NOTE: The sample accounting entries and financial statements in Appendix C illustrate pro forma accounting transactions pertaining to Federal oil and gas resources and the resulting financial statements. Data used in the pro forma transactions have been estimated by judgmentally extrapolating hypothetical numbers. These illustrative examples are not intended to provide guidance on determining the application of materiality.

The following pro forma transactions are compressed and simplified, and appropriately do not contain all of the detail associated with an event. For example, in transaction number two, the one-fifth bonus is invested until leases are accepted. Any interest accrued is refunded on bids subsequently rejected and returned. The illustration omits transactions internal to the entity. For example, transfers between sub-component entities are omitted.

Readers should not rely on the pro forma accounting transactions and resulting financial statements as a complete model for agency accounting. Certain omitted entries may be required in actual practice but are omitted since they are not required to understand the effect of the proposal on agency financial statements.

At the beginning of the fiscal year for which the accounting standards for oil and gas resources are effective, the following transaction is recorded by the component entity responsible for collecting royalties.

1. Record initial value of estimated petroleum royalties and the related liability for revenue distributions to others.

The initial value of estimated petroleum royalties used in this pro forma transaction is calculated for illustrative purposes only. The value of the Federal government's estimated petroleum royalties would be calculated based on the valuation of oil and lease condensate estimated petroleum royalties, natural gas plant liquids (NGPLs) estimated petroleum royalties, and gas estimated petroleum royalties on a regional basis. Formulas to be used to calculate the estimated petroleum royalties for oil and lease condensate, NGPLs, and gas on a regional basis are as follows:

For oil and lease condensate:

Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves X Regional Average First Purchase Price for Oil and Lease Condensate X Effective Regional Average Royalty Rate for Oil and Lease Condensate = Regional Estimated Petroleum Royalties for Oil and Lease Condensate

For NGPLs:

Regional Estimated Quantity of Proved NGPLs Reserves X Regional Average First Purchase Price for NGPLs X Effective Regional Average Royalty Rate for NGPLs = Regional Estimated Petroleum Royalties for NGPLs

For gas:

Regional Estimated Quantity of Proved Gas Reserves X Regional Average Wellhead Price for Gas X Effective Regional Average Royalty Rate for Gas = Regional Estimated Petroleum Royalties for Gas

The initial value of estimated petroleum royalties is a hypothetical number used for illustrative purposes only. The hypothetical initial value of estimated petroleum royalties is $150,677,667,470. The illustrative pro forma transaction to record the initial value of the Federal government's estimated petroleum royalties and related liability is presented below. The asset's value would be the royalty share of the Federal oil and gas resources classified as "proved reserves." The related liability would be for the royalty share of the Federal oil and gas resources classified as "proved reserves" designated to be distributed to others, i.e., the states, the general fund of the U.S. Treasury and other Federal component entities, including the component entity responsible for collecting royalties. The proposed treatment of distribution of revenue to others creates a Federal and a non-Federal liability for the component entity responsible for collecting royalties.

The cumulative effect of adopting this accounting standard would be reported as a "change in accounting principle" in accordance with SFFAS 21, *Reporting Corrections of Errors and Changes in Accounting Principles*. The adjustment would be made to the beginning net position on the component entity responsible for collecting royalties Statement of Changes in Net Position for the period the change is made. To obtain the value of the adjustment, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the component entity responsible for collecting royalties. For this illustration, one percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting royalties based on the average distribution for 2005.[39] To record the related liabilities the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[40] For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005.[41] These calculations are presented below:

$150,677,667,470 X .01 = $1,506,776,675

$150,677,667,470 X .84 = $126,569,240,675

$150,677,667,470 X .15 = $22,601,650,120

Dr Estimated Petroleum Royalties	150,677,667,470	
Cr Prior Period Adjustment: Change In Accounting Principle		1,506,776,675
Cr Liability for Revenue Distribution to Others-Federal		126,569,240,675
Cr Liability for Revenue Distribution to States-Non-Federal		22,601,650,120

To record initial value of estimated petroleum royalties due to change in accounting principle, the related liabilities to state and local governments, and the related liabilities to other Federal component entities. (The 1% expected to be retained by the entity responsible for making royalty collections increases its net position.)

<u>*Other Federal component entity entry:*</u>

For component entities, amounts must be recognized in a manner that supports elimination of Federal assets and liabilities and flow amounts. Therefore, the receiving Federal component entities

[39] The one percent was derived by dividing [Note 21. Custodial Distributions to MMS, Revenues to Fund Operations] by [Total Revenue on the Statement of Custodial Activity] for 2005.

[40] The 15 percent was derived by dividing [Note 21. Payments to States] by [Total Revenue on the Statement of Custodial Activity] for 2005.

[41] The 84 percent was derived by dividing [Transfers-out to other Federal component entities on the Statement of Custodial Activity] by [Total Revenue on the Statement of Custodial Activity] for 2005.

would be required to book the asset related to their respective interest in the estimated petroleum royalties.

Dr Long-Term A/R for Oil and Gas-Federal	126,569,240,675	
Cr Prior Period Adjustment: Change In Accounting Principle		126,569,240,675

To book the asset by other Federal entities for their respective interest in the estimated petroleum royalties.

2. Record payment of the one-fifth bonus bid amounts.

For a competitive lease sale, a notice of lease sale is published in the *Federal Register.* Each lease bid must include a payment for one-fifth of the bonus bid amount unless the bidder is otherwise directed by the Secretary. For purposes of this illustrative accounting event, four bonus bids were received with payment of the one-fifth bonus bid amount. Bonus bid number one was $1,850,000, bonus bid number two was $1,900,000, bonus bid number three was $1,950,000, and bonus number four was $2,000,000. The total payment relating to the four bonus bids was $1,540,000 (bonus bid number one for $370,000, bonus bid number two for $380,000, bonus bid number three for $390,000, and bonus bid number four for $400,000) and was recorded with the following entry by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	1,540,000	
Cr Unearned Revenue		1,540,000

To record collection of the one-fifth bonus bids for the four bonus bids.

3. Record remaining payment by the successful bidder and the annual rental fee and the related liability for revenue distributions to others.

Payment of the unpaid balance of the bonus bid amount and the first year's rental fee are to be received from the successful bidder on the 11th business day after receipt of the lease forms by the successful bidder. The successful bid was bonus bid number four in the amount of $2,000,000. The remaining four-fifths bonus bid of $1,600,000 and the first year rental fee in the amount of $360,000 is received. According to various legislative requirements, rental fees are required to be paid one year in advance and are recorded as revenue from rent when received because there is no obligation to refund unearned portions. The following entries are recorded by the component entity responsible for collecting royalties.

Dr Unearned Revenue		400,000	
Dr Fund Balance with Treasury	(1,600,000+360,000)	1,960,000	
Cr Revenue from Rent			360,000
Cr Revenue from Bonus Bid			2,000,000

To record remaining bonus payment and the annual rental fee by the successful bidder.

The related increase in the liability for the future revenue distributions to others from the rent and the bonus bid is calculated in two parts. One part is based on revenue designated as payments to the States. The other part is based on designated transfers-out to other Federal component entities. The revenue from rent and bonus bid is multiplied by the average share of the revenue distributed to the States to obtain the value of the rent and bonus bid revenue to be distributed to the States. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[42] The revenue from rent and bonus bid is multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent and bonus bid revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other component entities based on the average distribution for 2005.[43] These calculations are presented below:

$2,360,000 X .15 = $354,000

$2,360,000 X .84 = $1,982,400

Dr Revenue Designated for the States[44]	354,000	
Dr Transfers-Out	1,982,400	
Cr Liability for Revenue Distribution to Others-Federal		1,982,400
Cr Liability for Revenue Distribution to States-Non-Federal		354,000

To record the related increase in the liability for the future revenue distributions to others.

<u>*Other Federal component entity entry:*</u>

Dr Long-Term A/R for Gas and Oil-Federal	1,982,400	
Cr Transfer-In		1,982,400

To record the related accrual of a transfer-in and a reduction in the long-term A/R.

4. Receive the annual rental fee from pre-existing leases and record the related liability for revenue distributions to others.

For illustrative purposes, the total amount of annual rent collected for the year for offshore leases was $193,273,613 and the rental fee for onshore leases was $46,588,068 for a total of $239,861,681. Since $360,000 was received in connection with the new lease, the rental payments remaining are $239,501,681 ($239,861,681 less $360,000). The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	239,501,681	
Cr Revenue from Rent		239,501,681

To record rental payments on leases for the year.

The related increase in the liability for the future rent revenue to be distributed to others is calculated in two parts. One part is based on revenue designated as payments to the States. The other part is based on designated transfers-out to other Federal component entities. The revenue from rent is multiplied by the average share of the revenue distributed to the States to obtain the value of the rent revenue to be distributed to the States. For this illustration, 15 percent was used as an average

[42] See footnote 40.
[43] See footnote 41.
[44] This and certain other titles were selected for illustrative purposes. The entity has the option of selecting another account title, such as grant, that may be more appropriate.

annual share of the revenue distributed to the States based on the average distribution for 2005.[45] The revenue from rent is multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005.[46] These calculations are presented below:

$239,501,681 X .15 = $35,925,252

239,501,681 X .84 = $201,181,412

Dr Revenue Designated for the States	35,925,252	
Dr Transfers-out	201,181,412	
Cr Liability for Revenue Distribution to Others-Federal		201,181,412
Cr Liability for Revenue Distribution to States-Non-Federal		35,925,252

To record the related increase in the liability for the future revenue distributions to others.

Other Federal component entity entry:

Dr Long-Term A/R for Gas and Oil-Federal	201,181,412	
Cr Transfer-In		201,181,412

To record the related accrual of a transfer-in and a reduction in the long-term A/R.

5. Refund unsuccessful bidders' bonus bid deposits.

Bonus bid deposits submitted by unsuccessful bidders are refunded to respective bidders after bids are opened, recorded, and ranked. Bonus bid #1 in the amount of $370,000, bonus bid #2 in the amount of $380,000, and bonus bid #3 in the amount of $390,000 for a total of $1,140,000 are returned to respective bidders. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Unearned Revenue	1,140,000	
Cr Fund Balance with Treasury		1,140,000

To record refund of losing bonus bids.

The remaining pro-forma transactions and financial statements are presented as of the end of the Federal government's fiscal year (FY).

6. Record earned royalty revenue and depletion expense.

Earned royalty revenue should be recognized as exchange revenue by the component entity that is responsible for collecting the royalties. At the same time, an amount equal to the royalty collections should be recognized as depletion expense; and, the value of estimated petroleum reserves should be reduced by the depletion expense amount. Sales value and royalty payment information are due

[45] See footnote 40.
[46] See footnote 41.

on or before the last of the month following the month the oil or gas product from Federal oil and gas resources was sold or removed from the lease. For example, oil or gas sold in June must be reported by July 31, the end of the following month.

For illustrative purposes, the total amount of royalty revenue earned for the fiscal year for offshore and onshore rental leases was used in this calculation. The royalty revenue earned during the fiscal year for offshore leases was $3,563,921,973 and the royalty revenue earned during the fiscal year for onshore leases was $852,330,828 for a total of $4,416,252,801. The following entries are recorded by the component entity responsible for collecting royalties.

Dr Accounts Receivable	4,416,252,801	
Cr Revenue from Royalties for Federal Oil and Gas Reserves		4,416,252,801
To record earned royalty revenue.		
Dr Oil and Gas Depletion Expense	4,416,252,801	
Cr Estimated Petroleum Royalties		4,416,252,801
To record depletion expense for Federal oil and gas resources.		

7. Record collection of royalty revenue.

Royalty payments are due on or before the last of the month following the month the oil or gas product from Federal oil and gas resources are sold or removed from the lease, unless lease terms state that royalties are due otherwise. A year-to-date total of royalty revenue collected is in the amount of $4,048,231,734. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury	4,048,231,734	
Cr Accounts Receivable		4,048,231,734
To record collection of royalty revenue.		

8. Record distribution of bonus bid, rent, and royalty collections and the reduction in the liability for the revenue distributed to others.

The component entity responsible for collecting royalty revenue is required to distribute the bonus bid, rent, and royalty revenue in accordance with authoritative formulas to recipients designated by law upon matching the revenue collections to specific leases. The component entity distributing bonus bid, rent, and royalty revenue from Federal oil and gas resources should recognize the distribution to component entities in accordance with existing accounting standards. The Federal component entity receiving the distribution should recognize the receipt as a transfer in when calculating its operating results. For purposes of this illustrative accounting event, the bonus bid collected was $2,000,000, the rent collected was $239,861,681 and the royalties collected was $4,048,231,734 for total collections of $4,290,093,415.

The bonus bid, rent, and royalty revenue collections to be distributed and the related reduction in the liability for revenue distribution to others is calculated in two parts. One part is based on revenue collections designated as payments to the States. The other part is based on collections designated as payments to other Federal component entities. The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to the States to obtain the value of the collections to be distributed to the States. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[47] The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005.[48] These calculations are presented below:

$4,290,093,415 X .15 = $643,514,012

$4,290,093,415 X .84 = $3,603,678,469

Dr Liability for Revenue Distribution to Others-Federal	3,603,678,469	
Dr Liability for Revenue Distribution to States-Non-Federal	643,514,012	
Cr Fund Balance with Treasury		4,247,192,481

To record distribution of bonus bid, rent, and royalty revenue collections and the reduction in liabilities for revenue distribution to others.

<u>*Other Federal entity entry:*</u>

Dr Fund Balance with Treasury	3,603,678,469	
Cr Long-Term A/R for Oil and Gas-Federal		3,603,678,469

To increase the fund balance with treasury and reduce the long-term accounts receivable for oil and gas in relation to distributions received.

9. Disclose rights to future royalty streams identified for sale.

When rights to a future royalty stream are identified to be sold, the value of those rights should be disclosed as future royalty rights held for sale. They should be disclosed rather than reclassified because (1) the point in time for the sale of the future royalty rights may be uncertain or undecided and (2) the identified fields may continue to produce oil and/or gas and generate royalties. These two factors make it difficult to establish and maintain precise valuation information in advance of the sale. Disclosure of the approximate value at the balance sheet date alerts the reader to the pending sale and the potential value of the asset to be sold. The value of the rights identified for sale should be based on the estimated quantity of proved reserves, the first purchase price for oil or the wellhead price for gas, and the royalty rate for each specific field identified for potential sale.

Future royalty streams from two specific oil fields have been identified to be sold.

The estimated value of the future royalty stream identified to be sold from field number one is $5,305,000 based on the following calculation: 1,000,000 barrels to be sold X $42.44 per barrel per field number one first purchase price for oil X the 12.5% royalty rate for field number one.

The estimated value of the future royalty stream identified to be sold from field number two is $3,244,688 based on the following calculation: 750,000 barrels to be sold X $34.61 per barrel per

[47] See footnote 40.
[48] See footnote 41.

field number two first purchase price for oil X the 12.5% royalty rate for field number two. The future royalty streams are expected to be sold sometime during the next fiscal year.

10. Record sale of future royalty streams identified for sale and the related change in the liability for revenue distributions to others.

At the time the future royalty rights identified for sale are sold, the asset value is calculated based on the quantity of proved oil reserves involved in the sale, the first purchase price or the wellhead price for the field at the time of sale, and the royalty rate for the specific field. Any difference between the asset value of the future royalty rights sold and the sales proceeds results in a net gain or loss. The net gain or loss should be reported on the Statement of Net Cost of the component entity responsible for collecting royalty revenue. For purposes of this illustrative accounting event, the rights to future royalty rights held for sale for field number one had an asset value of $5,375,000 based on the following calculation: 1,000,000 barrels of proved oil reserves involved in the sale multiplied by an arbitrary $43.00 per field number one first purchase price per barrel further multiplied by the arbitrary 12.5 percent royalty rate for field number one. The rights to a future royalty stream from field number one were sold for $3,950,000. As a result, there is a loss of $1,425,000 on the sale of the future royalty stream from field number one, which should be reported on the Statement of Net Cost.

Dr. Fund Balance with Treasury	3,950,000	
Dr. Loss on Sale of Estimated Petroleum Royalties	1,425,000	
Cr. Estimated Petroleum Royalties		5,375,000

To record sale of future royalties.

The loss on the sale of estimated petroleum royalties is multiplied by the average share of the revenue distributed to the States and other Federal component entities to obtain the related reduction in the liabilities for revenue distributions to others. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[49] The revenue collections from bonus bid, rent, and royalties are multiplied by the average share of the revenue distributed to other Federal component entities to obtain the value of the rent revenue to be distributed to other Federal component entities. For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005.[50] This calculation is presented below:

$1,425,000 X .15 = $213,750

$1,425,000 X .84 = $1,197,000

Dr Liability for Revenue Distributions to Others- Federal	1,197,000	
Dr Liability for Revenue Distributions to States-Non-Federal	213,750	
Cr Revenue Designated for the States		213,750
Cr Transfers-Out		1,197,000

[49] See footnote 40.
[50] See footnote 41.

To record the related reduction in the liabilities for the future revenue distributions to others, revenue designated for the States, and transfers-out as a result of the loss on the sale of estimated petroleum royalties.

Dr Liability for Revenue Distributions to Others- Federal	3,318,000	
Dr Liability for Revenue Distributions to States-Non-Federal	592,500	
Cr Fund Balance with Treasury		3,910,500

To record the distribution of collections from the sale of revenue streams and the related reduction in the liability for revenue distributions to others.

Other Federal entity entry:

Dr. Fund Balance with Treasury	3,318,000	
Cr. Long-Term A/R for Oil and Gas-Federal		3,318,000

To increase the fund balance with treasury and reduce the long-term accounts receivable for oil and gas in relation to distributions received.

Dr. Transfers-In	1,197,000	
Cr Long-Term A/R for Oil and Gas-Federal		1,197,000

To decrease the transfers-in and long-term accounts receivable as a result of the loss on the sale of estimated petroleum royalties.

11. Record annual valuation of estimated petroleum royalties and the related change in the liability for revenue distributions to others.

The calculated value of the Federal government's estimated petroleum royalties for financial statement reporting at year-end should be compared to the book value of estimated petroleum royalties at year-end. If the calculated value of estimated petroleum royalties at year-end is greater than the year-end book value,[51] the book value should be increased to the new estimate and a gain should be recorded on the Statement of Net Cost of the reporting entity responsible for collecting revenue. If the calculated value of estimated petroleum royalties at year-end is less than the year-end book value, the book value should be decreased to the new estimate and a loss should be recorded on the Statement of Net Cost of the reporting entity responsible for collecting royalty revenue. For illustrative purposes, the valuation of estimated petroleum royalties as of as of the year ended September 30 produced a gain of $25,210,225,331 that is based on the following calculations.

The revaluation value of estimated petroleum royalties for oil and lease condensate from Federal leases is $83,357,750,000: ((14,000,000,000 barrels of proved oil and lease condensate reserves multiplied by an arbitrary price of $47.50 per barrel) further multiplied by an arbitrary 12.535 percent royalty rate)). The revaluation value of estimated petroleum royalties for NGPLs from Federal leases is $9,401,250,000: ((2,500,000,000 barrels of proved NGPLs reserves multiplied an arbitrary price of $30.00 per barrel) further multiplied by an arbitrary 12.535 percent royalty rate)). The revaluation value of estimated petroleum royalties for gas from Federal leases is $78,707,265,000:

[51] The estimated petroleum royalties beginning balance would have been reduced by the amount expensed on the statement of net cost.

((105,000,000,000 thousand cubic feet of proved gas reserves multiplied by an arbitrary price of $5.98 per thousand cubic feet) further multiplied by an arbitrary 12.535 percent royalty rate)).

The total revaluation value of estimated petroleum royalties for oil and lease condensate, NGPLs, and gas is $171,466,265,000. The current value of estimated petroleum royalties ($171,466,265,000) less the book value of estimated petroleum royalties (the initial value of estimated petroleum royalties at the beginning of the year (October) less depletion expense for estimated petroleum royalties through the end of the year (September 30), less the asset value of estimated petroleum royalties sold), equals the net gain to be recorded:

$171,466,265,000 – (150,677,667,470 – 4,416,252,801 – 5,375,000) = $25,210,225,331

Dr Estimated Petroleum Royalties	25,210,225,331	
Cr Gain on Revaluation of Estimated Petroleum Royalties		25,210,225,331

To record revaluation of estimated petroleum royalties.

To record the related increase in the liability for the future revenue distributions to others, the amount that the total estimated petroleum royalties was increased due to revaluation is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.[52] For this illustration, 84 percent was used as an average annual share of the revenue distributed to other Federal component entities based on the average distribution for 2005.[53] These calculations are presented below:

$25,210,225,331 X .15 = $3,781,533,800

$25,210,225,331 X .84 = $21,176,589,278

Dr Revenue Designated for the States	3,781,533,800	
Dr Transfers-Out	21,176,589,278	
Cr Liability for Revenue Distributions to Others-Federal		21,176,589,278
Cr Liability for Revenue Distributions to States-Non-Federal		3,781,533,800

To record the related year-end increase in the liabilities for the future revenue distributions to others.

Other Federal component entity entry:

For component entities, amounts must be recognized in a manner that supports elimination of Federal assets and liabilities and flow amounts. Therefore, the receiving Federal component entities would be required to book the revaluation amount related to their respective interest in the estimated petroleum royalties.

Dr Long-Term A/R for Oil and Gas-Federal	21,176,589,278	
Cr Transfers-In		21,176,589,278

To book the revalued asset amount by other Federal entities for their respective interest in the estimated petroleum royalties.

[52] See footnote 40.
[53] See footnote 41.

The trial balance, closing entries, and pro forma financial statements on the next two pages are illustrative of the departmental entries presented in this appendix. The “other Federal component entity” entries and the consolidated financial statements of the United States Government are not illustrated.

Pre-closing trial balance after pro forma transactions:

Fund Balance with Treasury	42,940,434
Accounts Receivable	368,021,067
Estimated Petroleum Royalties	171,466,265,000
Liability for Revenue Distributions to Others-Federal	(144,340,800,296)
Liability for Revenue Distributions to States-Non-Federal	(25,775,142,910)
Revenue from Bonus Bid	(2,000,000)
Revenue from Rents	(239,861,681)
Revenue from Royalties	(4,416,252,801)
Transfers-Out	21,378,556,090
Oil and Gas Depletion Expense	4,416,252,801
Revenue Designated for the States	3,817,599,302
Gain on Revaluation of Estimated Petroleum Royalties	(25,210,225,331)
Loss on Sale of Future Royalty Rights	1,425,000
Prior Period Adjustment: Change in Accounting Principle	(1,506,776,675)
Total	0

Closing Entries:

Revenue from Bonus Bid	2,000,000	
Revenue from Rent	239,861,681	
Revenue from Royalties	4,416,252,801	
Gain on Revaluation of Estimated Petroleum Royalties	25,210,225,331	
Prior Period Adjustments: Change in Accounting Principle	1,506,776,675	
Cumulative Results of Operations		1,761,283,295
Transfers-Out		21,378,556,090
Oil and Gas Depletion Expense		4,416,252,801
Revenue Designated for the States		3,817,599,302
Loss on Sale of Future Royalty Rights		1,425,000

Post-closing trial balance:

Fund Balance with Treasury	42,940,434
Accounts Receivable	368,021,067
Estimated Petroleum Royalties	171,466,265,000
Liability for Revenue Distributions to Others-Federal	(144,340,800,296)
Liability for Revenue Distributions to States- N0n-Federal	(25,775,142,910)
Cumulative Results of Operations	(1,761,283,295))
Total	0

Pro Forma Financial Statements – for fiscal year ended 9/30/20XX

Balance Sheet

Assets	
Fund Balance with Treasury	42,940,434
Accounts Receivable	368,021,067
Estimated Petroleum Royalties	171,466,265,000
Total Assets	$ 171,877,226,501
Liability for Revenue Distributions to Others-Federal	144,340,800,296
Liability for Revenue Distributions to States-Non-Federal	25,775,142,910
Total Liabilities	170,115,943,206
Net Position	
Cumulative Results of Operations	1,761,283,295
Total Liabilities and Net Position	$ 171,877,226,501

Statement of Net Cost

Oil and Gas Resources Program

Leasing Activities:	
Costs (Oil and Gas Depletion Expense)	$ 4,416,252,801
Less: Earned Revenue	(4,658,114,482)
Net Cost/(Revenue) from Leasing Operations	(241,861,681)
Loss/(Gain) on Revaluation of Estimated Petroleum Royalties	(25,210,225,331)
Less: Revenue Designated for the States	3,817,599,302
Less: Loss on Sale of Future Royalty Rights	1,425,000
Net Cost/(Revenue) for Program	$(21,633,062,710)

Statement of Changes in Net Position

Beginning Net Position	$ 0
Adjustment: Change in Accounting Principle	1,506,776,675
Beginning Balance, as adjusted	1,506,776,675
Net Revenue for Program	21,633,062,710
Transfers In/(Out)	(21,378,556,090)
Ending Net Position	$ 1,761,283,295

APPENDIX D: ILLUSTRATIVE DISCLOSURE AND RSI PRESENTATIONS

PLEASE NOTE: Appendix D illustrates the type of reporting contemplated by the Board. Information presented in the illustrative disclosure and RSI presentations are based on hypothetical numbers. Therefore, readers should not rely on the validity of the data in the sample presentations.

NOTE X -- ESTIMATED PETROLEUM ROYALTIES

Management of Federal Oil and Gas Resources

The Minerals Management Service (MMS) plays an integral part in the implementation of the President's national energy policy (NEP). The NEP is a comprehensive strategy designed to secure America's energy future by reducing dependence on foreign sources, increasing domestic fossil fuel production, improving energy conservation efforts, and developing alternative and renewable energy sources. The MMS is responsible for managing the nation's oil and natural gas resources on the Outer Continental Shelf (OCS) and the mineral revenues from the OCS and Federal lands. The MMS management process can be broken down into six essential analysis components: pre-leasing, post-leasing and pre-production, production and post-production, revenue collection, fund disbursement, and revenue compliance.

Stewardship Policies for Federal Oil and Gas Resources

The MMS's responsibilities as stewards of the physical oil and gas resources on the OCS begin when the MMS conducts pre-leasing analysis activities, which include the assessment of oil and gas resources that may be offered for lease. Following the pre-leasing assessment, the MMS develops a plan for offering those resources to developers. In the case of oil and gas development, this planning process is designed to consider both the environmental and economic concerns of the nation by providing opportunities for input from the public, the private sector, states, and Congress. The MMS conducts public planning processes for each individual lease sale.

Once a sale is completed, the MMS evaluates the bids to ensure that the government receives fair market value. The evaluation determines whether the bid can be accepted and a lease issued. Once a lease is assigned to a winning bidder, the MMS begins post-leasing and pre-production activities. These activities include a permitting and approval process for all exploration, development, and production activities proposed by the lease operators. MMS staff inspects each operation in order to confirm that all activities are conducted in an environmentally and physically safe manner. Similar inspections also occur during the production and post-production activities with the added responsibility of ensuring the Federal government is receiving accurate royalties from production, while inspections during the post-production phase help ensure that facilities are decommissioned in a manner that protects the environment.

Once a lease is in place, the Federal government's share of production from both offshore and onshore operations may be recovered as royalty-in-value (RIV) or royalty-in-kind (RIK). Through royalty revenue collection and fund disbursement, the MMS achieves optimal value by ensuring that all revenues from Federal oil and gas lease are efficiently, effectively, and accurately collected, accounted for, and disbursed to states, other Federal component entities, and the U.S. Treasury. The MMS also performs revenue compliance activities to ensure the Federal government has received fair market value and that companies comply with applicable laws, regulations, and lease terms.

Through this robust mineral asset management process, the MMS serves as a leading mineral asset manager for the Federal government, the states, and the American people.

Future Royalty Streams Identified for Sale

Future royalty streams from two specific oil fields have been identified to be sold.

The estimated value of the future royalty stream identified to be sold from field number one in the Gulf of Mexico is $5,305,000 based on the following calculation: The royalty stream from 1,000,000 barrels are to be sold at a $42.44 sale price per barrel per field number one first purchase price for oil with a 12.5 percent royalty rate for field number one.

The estimated value of the future royalty stream identified to be sold from field number two in the Gulf of Mexico is $3,244,688 based on the following calculation: The royalty stream from 750,000 barrels are to be sold at a $34.61 sale price per barrel per field number two first purchase price for oil with a 12.5 percent royalty rate for field number two.

The future royalty streams are expected to be sold sometime during the next fiscal year.

Revenue Reported by Category
Fiscal year 20XX

	Federal Offshore	Federal Onshore	Total
Oil and Lease Condensate Royalty	1,703,801,070	401,102,615	2,104,903,685
NGPLs Royalty	340,110,343	150,120,157	490,230,500
Gas Royalty	$1,520,010,560	$301,108,056	$1,821,118,616
Subtotal	$3,563,921,973	$852,330,828	$4,416,252,801
Rent	$193,273,613	$46,588,068	$239,861,681
Bonus Bid	2,000,000	0	2,000,000
Subtotal	$195,273,613	$46,588,068	$241,861,681
Total	$3,759,195,586	$898,918,896	$4,658,114,482

The disclosure for revenue reported by category presents oil and lease condensate royalty revenue, natural gas plant liquids (NGPLs) royalty revenue, gas royalty revenue, rent revenue, and bonus bid revenue by offshore leases and by onshore leases for the current reporting period. In addition, totals for the gas royalty revenue category, NGPLs royalty revenue category, the oil and lease condensate royalty revenue category, the rent revenue category, and the bonus bid revenue category are reported, with a total for all revenue reported.

ESTIMATED PETROLEUM ROYALTIES
Fiscal Year 20XX

Beginning of FY[54]	Quantity	Purchase Price ($)	Royalty Rate (%)	Asset Value ($)
Oil and Lease Condensate (Barrels)	13,555,200,000	$40.56/Barrel	13.58%	$74,662,692,250
NGPLs (Barrels)	2,347,450,000	$23.00/Barrel	9.5%	5,129,178,250
Gas (Mcf)[55]	100,106,760,000,000	$4.86/Mcf	14.57%	70,885,796,070
Beginning of FY Total				$150,677,667,470

End of FY	Quantity	Purchase Price ($)	Royalty Rate (%)	Asset Value ($)
Oil and Lease Condensate (Barrels)	14,000,000,000	$47.50/Barrel	12.535%	$83,357,750,000
NGPLs (Barrels)	2,500,000,000	$30.00/Barrel	12.535%	9,401,250,000
Gas (Mcf)	105,000,000,000,000	$5.98/Mcf	12.535%	78,707,265,000
End of FY Total				$171,466,265,000

This disclosure provides estimated petroleum royalties for the beginning of the current reporting period and the end of the current reporting period.

The increase in the asset value was a result in the changes involved in valuing the asset. During the current reporting period, there was an increase in the quantity of proved oil and lease condensate, NGPLs, and gas reserves. There was a decrease in the royalty rates for oil and lease condensate and gas leases in effect, but an increase for NGPLs. However, there was a 17 percent increase in the unit price of oil and lease condensate (price per barrel), a 30 percent increase in the unit price for NGPLs (price per barrel), and a 23 percent increase in the unit price of gas (price per 1000 cubic feet) during the reporting period.

[54] Fiscal Year.
[55] Thousand cubic feet.

REQUIRED SUPPLEMENTARY INFORMATION

Federal Regional Oil and Gas Sales Information

Table 1 on the following page reflects sales volume, sales value, royalty revenue earned, and estimated value for royalty relief information for fiscal year 20XX.

Sales volume represents the quantity of a mineral commodity sold during the reporting period. Sales value represents the dollar value of the mineral commodity sold during the reporting period. Royalty revenue earned represents a stated share or percentage of the value of the mineral commodity produced.

Royalty relief is the reduction, modification, or elimination of any royalty payment due to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. The estimated value for royalty relief is an approximated calculation of royalty relief. The estimated value for royalty relief is calculated based on a formula developed by the Department of the Interior.

The sales volume, sales value, royalty revenue earned, and the estimated value for royalty relief are presented on a regional basis. The information is presented on a regional basis to provide users of the financial statements with the regional variances in the prices of oil and gas for decision-making purposes, to reflect the amount of royalty relief granted and to forecast future royalty revenue.

Table 1
Federal Regional Oil and Gas Information
FY 20XX Natural Gas Plant Liquids (NGPLs) Information

Region	Sales Volume (Barrels)	Sales Value ($)	Royalty Revenue Earned ($)	Estimated Value for Royalty Relief ($)
Alaska	504,907,460	$7,182,415,240	$1,055,380,640	N/A[56]
Pacific	455,613,460	5,737,146,080	822,800,200	N/A
Gulf of Mexico	562,808,260	10,272,610,500	1,470,661,910	3,250,000,000
Onshore Region I	453,335,320	8,912,195,960	1,345,077,330	N/A
Onshore Region II	399,821,380	7,290,095,980	1,108,931,700	N/A
Totals	2,376,485,880	$39,394,463,760	$5,802,851,780	$3,250,000,000

FY 20XX Oil and Lease Condensate Information

Region	Sales Volume (Barrels)	Sales Value ($)	Royalty Revenue Earned ($)	Estimated Value for Royalty Relief ($)
Alaska	366,036,900	5,091,864,970	783,276,870	N/A
Pacific	408,378,420	6,298,080,860	946,205,710	N/A
Gulf of Mexico	120,825,580	2,098,806,440	216,537,590	N/A
Onshore Region I	5,103,168,000	12,884,627,080	2,045,301,890	N/A
Onshore Region II	5,005,101,640	10,170,031,760	1,934,356,820	N/A
Totals	11,003,510,540	$36,543,411,110	$5,925,678,880	N/A

FY 20XX Gas Information

Region	Sales Volume (Mcf[57])	Sales Value ($)	Royalty Revenue Earned ($)	Estimated Value for Royalty Relief ($)
Alaska	4,700,496,060	$13,601,758,780	$2,093,260,060	N/A
Pacific	4,983,485,730	12,221,150,850	1,934,356,820	N/A
Gulf of Mexico	5,103,168,000	12,884,627,080	2,045,301,890	4,050,100,000
Onshore Region I	4,700,952,680	10,345,025,220	1,649,297,130	N/A
Onshore Region II	4,658,177,090	7,653,957,630	1,198,395,780	N/A
Totals	24,146,279,560	$56,706,519,560	$8,920,611,680	$4,050,100,000

[56] N/A means not applicable.
[57] Thousand cubic feet.

Historical Comparisons of Proved Reserves

This overview summarizes the 2004 proved reserves balances of oil and lease condensate, gas (dry), and natural gas plant liquids on a national level and provides historical comparisons between 2004 and prior years. **Table 2**, on the following page, lists the estimated annual reserve balances since 1994 for oil and lease condensate, gas, and natural gas plant liquids.

Oil and Lease Condensate. The United States (U.S.) had 21,371 million barrels of oil and lease condensate proved reserves as of December 31, 2004. Oil and lease condensate proved reserves declined by two percent in 2004 owing mostly to a large nine percent decrease in the Gulf of Mexico. Boosted by reserves additions in Wyoming, Montana, North Dakota, and Texas, the oil and lease condensate proved reserves of the onshore lower 48 States increased by 0.1 percent. However, three of the four largest crude oil reserves areas, the Gulf of Mexico, Alaska, and California, registered reserves declines. U.S. new field discoveries were the lowest in 12 years and as a result operators only replaced 71 percent of oil and lease condensate production with reserves additions.

Total discoveries are those new reserves attributable to extensions of existing fields, new field discoveries, and new reservoir discoveries in old fields. They result from the drilling of new wells. Total discoveries of oil and lease condensate were 782 million barrels in 2004, 37 percent less than those of 2003. The U.S. discovered an average of 1,105 million barrels of new oil and lease condensate proved reserves per year in the prior 10 years. Total discoveries in 2004 were 29 percent lower than that average.

Gas (Dry). The net of revisions, adjustments, sales, and acquisitions was 2,474 billion cubic feet in 2004, 37 percent lower than the post-1976 U.S. average (3,911 billion cubic feet per year). For the sixth year in a row (and 10 out of the last 11 years, the annual change to the national total of gas reserves has been positive, not negative. The U.S. had 192,513 billion cubic feet of dry natural gas reserves as of December 31, 2004, a two percent increase over the 2003 level. All natural gas proved reserves data shown in this report exclude natural gas held in underground storage. U.S. natural gas reserves increased for the sixth year in a row in 2004. The U.S. total went up even though Gulf of Mexico natural gas proved reserves dropped an unusually large 15 percent primarily due to low new discoveries. Discoveries of new gas fields nationwide were the lowest in 12 years. Nevertheless, because onshore lower 48 States total discoveries were almost 18 trillion cubic feet, total U.S. reserves additions replaced 118 percent of 2004 dry gas production. U.S. dry gas production declined one percent in 2004. Twenty percent of U.S. dry natural gas production comes from the Gulf of Mexico Federal Offshore which reported a 10 percent drop in production in 2004. Hurricane Ivan caused infrastructure damage that impacted oil and gas production in the Gulf in the last quarter of 2004 and will also reduce 2005 Gulf production from what it could have been.

Total discoveries are those reserves attributable to field extensions, new field discoveries, and new reservoir discoveries in old fields; they result from drilling exploratory wells. Total discoveries of dry natural gas reserves were 20,163 billion cubic feet in 2004, a five percent increase from the level reported in 2003. About 32 percent of the total discoveries were in Texas, 16 percent were in Wyoming, 10 percent were in the Gulf of Mexico Federal Offshore, 10 percent were in Louisiana, 10 percent were in Oklahoma, and six percent were in New Mexico.

Natural Gas Plant Liquids. U.S. natural gas plant liquids proved reserves increased 6 percent to 7,928 million barrels in 2004, rebounding from the decline observed in 2003. Reserve additions replaced 157 percent of 2004 natural gas plant liquids production. The reserves of seven areas account for 88 percent of the nation’s natural gas plant liquids proved reserves: Texas- 35 perecent, Utah – Wyoming-12 percent, New Mexico-11 percent, Oklahoma-10 percent, Gulf of Mexico Federal Offshore-9 percent, Colorado-6 percent, and Alaska-5 percent.

Total discoveries of natural gas plant liquids reserves were 814 million barrels in 2004, an increase of 11 percent from 2003 (736 million barrels).

Table 2. Total U.S. Proved Reserves of Oil and Lease Condensate, Dry Gas, and Natural Gas Plant Liquids, 1994-2004

Year	Adjustments (1)	Net Revisions (2)	Revisions and Adjustments (3)	Net of Sales and Acquisitions (4)	Extensions (5)	New Field Discoveries (6)	Discoveries in Old Fields (7)	Total Discoveries (8)	Estimated Production (9)	Proved Reserves (10)	Change from Prior Year (11)
	Oil and Lease Condensate (million barrels of 42 U.S. gallons)										
1994	189	1,007	1,196	NA	397	64	111	572	2,268	22,457	-500
1995	122	1,028	1,150	NA	500	114	343	957	2,213	22,351	-106
1996	175	737	912	NA	543	243	141	927	2,173	22,017	-334
1997	520	914	1,434	NA	477	637	119	1,233	2,138	22,546	+529
1998	-638	518	-120	NA	327	152	120	599	1,991	21,034	-1,512
1999	139	1,819	1958	NA	259	321	145	725	1,952	21,765	+731
2000	143	746	889	-20	766	276	249	1,291	1,880	22,045	+280
2001	-4	-158	-162	-87	866	1,407	292	2,565	1,915	22,446	+401
2002	416	720	1,136	24	492	300	154	946	1,875	22,677	+231
2003	163	94	257	-398	426	705	101	1,232	1,877	21,891	-786
2004	74	420	494	23	617	33	132	782	1,819	21,371	-520
	Dry Gas (billion cubic feet, 14.73 psia, 60 degrees Fahrenheit)										
1994	1,945	5,484	7,429	NA	6,941	1,894	3,480	12,315	18,322	163,837	+1,422
1995	580	7,734	8,314	NA	6,843	1,666	2,452	10,961	17,966	165,146	+1,309
1996	3,785	4,086	7,871	NA	7,757	1,451	3,110	12,318	18,861	166,474	+1,328
1997	-590	4,902	4,312	NA	10,585	2,681	2,382	15,648	19,211	167,223	+749
1998	-1,635	5,740	4,105	NA	8,197	1,074	2,162	11,433	18,720	164,041	-3,182
1999	982	10,504	11,486	NA	7,043	1,568	2,196	10,807	18,928	167,406	+3,365
2000	-891	6,962	6,071	4,031	14,787	1,983	2,368	19,138	19,219	177,427	+10,021
2001	2,742	-2,318	424	2,630	16,380	3,578	2,800	22,758	19,779	183,460	+6,033
2002	3,727	937	4,664	380	14,769	1,332	1,694	17,795	19,353	186,946	+3,486
2003	2,841	-1,638	1,203	1,034	16,454	1,222	1,610	19,286	19,425	189,044	+2,098
2004	-114	744	630	1,844	18,198	759	1,206	20,163	19,168	192,513	+3,469
	Natural Gas Plant Liquids (million barrels of 42 U.S. gallons)										
1994	43	197	240	NA	314	54	131	499	791	7,170	-52
1995	192	277	469	NA	432	52	67	551	791	7,399	+229
1996	474	175	649	NA	451	65	109	625	850	7,823	+424
1997	-14	289	274	NA	535	114	90	739	864	7,973	+150
1998	-361	208	-153	NA	383	66	88	537	833	7,524	-449
1999	99	727	826	NA	313	51	88	452	896	7,906	+382
2000	-83	459	376	145	645	92	102	839	921	8,345	+439
2001	-429	-132	-561	102	717	138	142	997	890	7,993	-352
2002	62	31	93	54	612	48	78	738	884	7,994	+1
2003	-338	-161	-499	30	629	35	72	736	802	7,459	-535
2004	273	97	370	112	734	26	54	814	827	7,928	+469

Technically Recoverable Oil and Gas Resources

Technically recoverable resources is the term used to describe the total quantity of undiscovered recoverable resources and unproved reserves. Proved reserves are not included in the estimated quantity of technically recoverable resources. Technically recoverable resources that underlie Federally administered lands pertaining to Federal oil and gas resources are listed in **Table 3** on the following page. These estimates are based on national assessments performed by the United States Geological Survey (USGS) for onshore areas and those offshore waters subject to State jurisdiction, and the Minerals Management Service (MMS) for those offshore waters under Federal jurisdiction. It is estimated that 78.6 percent of the technically recoverable resources of crude oil, 61.6 percent of the dry gas resources, and 22.4 percent of the natural gas liquids resources underlie Federal lands.

While the specific locations of estimated undiscovered recoverable resources are not yet known, they are believed to exist in geologically favorable settings. Discovered recoverable resources are those economically recoverable quantities of oil and gas for which specific locations are known. Unproved reserves are based on geologic or engineering information similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves from being classified as proved.

While the estimation of technically recoverable resources is certainly a more imprecise endeavor than is the estimation of proved reserves, it is clear that substantial volumes of technically recoverable oil and gas resources remain to be found and produced domestically. Current estimates indicate that as much domestic gas remains to be found and then produced as has been to date. Of course, much effort, investment and time will be required to bring this gas to market.

There is a perception that the oil resource base has been more intensively developed than the gas resource base. And in fact, more oil has been produced in the U.S. than is estimated as remaining recoverable. Nevertheless, the ratio of unproven technically recoverable oil resources to 2004 oil production (**Table 3**) was about 88 to 1, higher than the comparable gas ratio.

TABLE 3

TECHNICALLY RECOVERABLE RESOURCES
As of December 31, XXXX

Area	Jurisdiction	Oil and Lease Condensate (billion barrels)	Gas (Dry) (trillion cubic feet)	Natural Gas Plant Liquids (billion barrels)
Technically Recoverable Resources				
Alaska Onshore + State Offshore	Federal	3.75	33.97	0.54
Alaska Onshore + State Offshore	Other	4.68	95.37	0.61
Alaska Federal Offshore	Federal	24.90	122.60	0.00
Lower 48 States Onshore + State Offshore	Federal	3.79	23.97	1.26
Lower 48 States Onshore + State Offshore	Other	17.83	166.41	5.64
Lower 48 States Federal Offshore	Federal	50.10	239.60	0.00
Alaska Subtotal		33.33	251.94	1.15
Alaska Percentage Federal		86.0%	62.1%	47.0%
Lower 48 States Subtotal		71.72	429.98	6.90
Lower 48 States Percentage Federal		75.1%	61.3%	18.3%
Total Technically Recoverable Resources		**105.05**	**681.92**	**8.05**
Percentage Federal		**78.6%**	**61.6%**	**22.4%**

Notes:
1. Proved Reserves are not included in these estimates.
2. Federal Onshore excludes Indian and Native lands even when federally managed in trust.
3. Zero (0.00) indicates either that none exists in this area or that no estimate of this resource has been made for this area.
4. Federal Offshore indicates MMS estimates for Federal Offshore jurisdictions (Outer Continental Shelf and deeper water areas seaward of State Offshore).

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APPENDIX E: GLOSSARY

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Definitions of Resource and Reserve Components and Subcomponents

Provided below are definitions used by Federal entities to describe oil and gas resource and reserve components and subcomponents. The source of these definitions is OCS Report MMS 2003-050 unless otherwise noted.

Resources estimated from broad geologic knowledge or theory and existing outside of known fields or known accumulations are undiscovered resources. Undiscovered resources can exist in untested prospects on unleased acreage, or on undrilled lease acreage, or in known fields. In known fields, undiscovered resources occur in undiscovered pools that are controlled by distinctly separate structural features or stratigraphic conditions.

The Mineral Management Service (MMS) and the U.S. Geological Survey (USGS) formerly conducted national assessments of undiscovered oil and gas resources together. The former was responsible for the offshore while the latter was responsible for onshore and state waters. The last such assessment was in 1995. MMS updates their assessment approximately every five years in accordance with the Department of Interior's five-year leasing program, with the last update in 2000. Since 1995, the USGS has not conducted an overall update for onshore and state waters, but has conducted assessments updates on a basin or area level.

The assessment considers recent geophysical, geological, technological, and economic information and uses a geologic play analysis approach for resource appraisal.

<u>Undiscovered Resources</u>

Undiscovered resources are hydrocarbons estimated on the basis of geologic knowledge and theory to exist outside of known accumulations. They are presumed to occur in unmapped and unexplored areas. The speculative and hypothetical resource categories comprise undiscovered resources. Undiscovered resources are classified as either “undiscovered non-recoverable resources” or “undiscovered recoverable resources”.

- Undiscovered Non-Recoverable Resources

The portion of undiscovered petroleum-initially-in-place quantities not currently considered to be recoverable. A portion of these quantities may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data is acquired.

- Undiscovered Recoverable Resources

An assessment provides estimates of undiscovered recoverable resources in two categories for Federal offshore oil and gas resources. However assessments for Federal onshore oil and gas resources provide information for only one, the undiscovered, conventionally recoverable resources. Both are described below:

1. Undiscovered, conventionally recoverable resources: The portion of the hydrocarbon potential that is producible, using present or reasonably foreseeable technology, without any consideration of economic feasibility.

2. Undiscovered, economically recoverable resources: The portion of the undiscovered conventionally recoverable resources that is economically recoverable under imposed economic scenarios.

Discovered Resources

Once leased acreage is drilled and is determined to contain oil or gas under Code of Federal Regulations (CFR) Title 30, Part 250, Subpart A, Section 11, Determination of Well Producibility (hereinafter referred to as 30 CFR 250.11), the lease is considered to have discovered resources.

Identified resources are resources whose location and quantity are known or are estimated from specific geologic or engineering evidence and include economic, marginally economic, and subeconomic components.

Reserves

In accordance with the Society of Petroleum Engineers (SPE), the World Petroleum Congresses (WPC), and the American Association of Petroleum Geologists (AAPG), the definition for "reserves" and the following explanatory paragraphs are presented as follows[58]:

> "Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data."

The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either 1) unproved or 2) proved.

Unproved Reserves

After a lease qualifies under 30 CFR 250.11, the MMS Field Naming Committee reviews the new producible lease to assign it to an existing field or, if the lease is not associated with an established geologic structure, to a new field. Regardless of where the lease is assigned, the reserves associated with the lease are initially considered to be unproved reserves. Unproved reserves are based on geologic or engineering information similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves from being classified as proved.

Unproved reserves may be divided into two subclassifications, possible and probable, which are similarly based on the level of uncertainty.

[58] WPC/SPE/AAPG Petroleum Reserves and Resources Definitions.

"Unproved possible reserves are less certain than unproved probable reserves and can be estimated with a low degree of certainty, which is insufficient to indicate whether they are more likely to be recovered than not. Reservoir characteristics are such that a reasonable doubt exists that the project will be commercial" (SPE, 1987). After a lease qualifies under 30 CFR 250.11, the reserves associated with the lease are initially classified as unproved possible.

"Unproved probable reserves are less certain than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to be recovered than not" (SPE, 1987). Reserves in fields for which a schedule leading to a Development and Production Plan (DPP) has been submitted to the MMS have been classified as unproved probable.

Proved Reserves

"Proved reserves can be estimated with reasonable certainty to be recoverable under current economic conditions, such as prices and costs prevailing at the time of the estimate. Proved reserves must either have facilities that are operational at the time of the estimate to process and transport those reserves to market or a commitment or reasonable expectation to install such facilities in the future" (SPE, 1987). Proved reserves can be subdivided into undeveloped and developed.

Proved undeveloped reserves are classified proved undeveloped when a relatively large expenditure is required to install production and/or transportation facilities, a commitment by the operator is made, and a timeframe to begin production is established. Proved undeveloped reserves are reserves expected to be recovered from (1) yet undrilled wells, (2) deepening existing wells, or (3) existing wells for which a relatively large expenditure is required for recompletion.

Proved developed reserves are classified as proved developed when the reserves are expected to be recovered from existing wells (including reserves behind pipe). Reserves are considered developed only after necessary production and transportation equipment have been installed or when the installation costs are relatively minor. Proved developed reserves are subcategorized as producing or non-producing" (SPE, 1987). This distinction is made at the reservoir level and not at the field level.

- Any developed reservoir in a developed field that has not produced or has not had sustained production during the past year is considered to contain proved developed nonproducing reserves. This category includes reserves contained in nonproducing reservoirs, contained reserves behind-pipe, and reservoirs awaiting well workovers or transportation facilities.

- Once the first reservoir in a field begins production, the reservoir is considered to contain proved developed producing reserves, and the field is considered on production. If a reservoir had sustained production during the last year, it is considered to contain proved developed producing reserves.

Production represents the proved oil and gas reserves that were extracted from existing reserves.[59]

End of the terms in Illustration 1 that are defined under the subheading **Definitions of Resource and Reserve Components and Subcomponents**

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Historical Estimates of Proved Reserves

Acquisitions: The volume of proved reserves gained by the purchase of existing fields or properties, from the date of purchase or transfer.

Adjustments: The quantity which preserves an exact annual reserves balance within each State or State subdivision of the following form:

> These adjustments are the yearly changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed. For example, variations as a result of changes in the operator frame, different random samples or imputations for missing or unreported reserve changes, could contribute to adjustments.

Change from Prior Year: the net change between proved reserves reported for the prior reporting period and proved reserves reported for the current reporting period.

Extensions: The reserves credited to a reservoir because of enlargement of its proved area. Normally the ultimate size of newly discovered fields, or newly discovered reservoirs in old fields, is determined by wells drilled in years subsequent to discovery. When such wells add to the proved area of a previously discovered reservoir, the increase in proved reserves is classified as an extension.

Net of Sales and Acquisitions: the net change in the quantity of reserve estimates, either positive or negative, as a result of reserves gained through purchase and deducted through sale during the report year.

New Field Discoveries: The volumes of proved reserves of crude oil, natural gas and/or natural gas liquids discovered in new fields during the report year.

New Reservoir Discoveries in Old Fields: The volumes of proved reserves of crude oil, natural gas, and/or natural gas liquids discovered during the report year in new reservoir(s) located in old fields.

Estimated Production, Crude Oil: The volumes of crude oil which are extracted from oil reservoirs during the report year. These volumes are determined through measurement of the volumes delivered from lease storage tanks, (i.e., at the point of custody transfer) with adjustment for (1) net

[59] Adapted from Gas Energy Review, Gas Supply and Demand Committee, July 1995, Vol.23 No.7.

differences between opening and closing lease inventories, and for (2) basic sediment and water. Oil used on the lease is considered production.

Estimated Production, Natural Gas, Dry: The volume of natural gas withdrawn from reservoirs during the
report year less (1) the volume returned to such reservoirs in cycling, repressuring of oil reservoirs and conservation operations; less (2) shrinkage resulting from the removal of lease condensate and plant liquids; and less (3) nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Volumes of gas withdrawn from gas storage reservoirs and native gas, which has been transferred to the storage category, are not considered production. This is not the same as marketed production, since the latter also excludes vented and flared gas, but contains plant liquids.

Estimated Production, Natural Gas Liquids: The volume of natural gas liquids removed from natural gas in lease separators, field facilities, gas processing plants or cycling plants during the report year.

Proved Reserves: The total quantity of proved reserves which is calculated by adding the quantity of reserves reported as revisions and adjustment, net of sales and acquisitions, total recoveries and deducting estimated production during the report year.

Revisions: Changes to prior year-end proved reserves estimates, either positive or negative, resulting from new information other than an increase in proved acreage (extension). Revisions include increases of proved reserves associated with the installation of improved recovery techniques or equipment. They also include correction of prior report year arithmetical or clerical errors and adjustments to prior year-end production volumes to the extent that these alter reported prior year reserves estimates.

Revisions and Adjustments: the net change in the quantity of reserve estimates, either positive or negative, as a result of adding changes reported as revisions and adjustments during the report year.

Sales: The volume of proved reserves deducted from an operator's total reserves when selling an existing field or property, during the calendar year.

Total Discoveries: the total quantity of additional discovered reserves which is calculated by adding the quantity of reserves reported as a result of extensions, the quantity of reserves reported as a result of new field discoveries, and the quantity of reserves reported as a result of discoveries in old fields during the report year.

End of the terms under the subheading **Historical Estimates of Proved Reserves**

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Other Definitions

Basin: The site of accumulation of a large thickness of sediments.[60]

[60] U.S. Geological Survey, Geologic Glossary.

Bonus Bid: Leases issued in areas known to contain minerals are awarded through a competitive bidding process. A bonus bid**,** as used in these standards, represents the cash amount successfully bid to win the rights to a lease.[61]

Crude oil is a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include: 1) small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well gas in lease separators, and that subsequently are commingled with the crude oil stream without being separately measured; and, 2) small amounts of nonhydrocarbons produced with the oil.

Dry Gas: The actual or calculated volumes of natural gas which remain after: 1. The liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation) 2. Any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable.

Estimated petroleum royalties means the estimated end-of-period value of the Federal government's royalty share of proved oil and lease condensate, NGPLs, and gas reserves from Federal oil and gas resources.

Estimated Value for Royalty Relief: Existing statutes authorize the Minerals Management Service (MMS) to grant royalty relief to operators on the production of oil and gas resources from Federal oil and gas leases. Royalty relief is the reduction, modification, or elimination of any royalty to operators to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. The estimated value for royalty relief is the calculated approximation of royalty relief. The estimated value for royalty relief is calculated based on a formula developed by the Department of the Interior.

Federal Oil and Gas Resources: Oil and gas resources over which the Federal government may exercise sovereign rights with respect to exploration and exploitation and from which the Federal government has the authority to derive revenues for its use. Federal oil and gas resources do not include resources over which the Federal government acts as a fiduciary for the benefit of a nonfederal party.

Federal jurisdiction is defined under accepted principles of international law. The seaward limit is defined as the farthest of 200 nautical miles seaward of the baseline from which the breadth of the territorial sea is measured or, if the continental shelf can be shown to exceed 200 nautical miles, a distance not greater than a line 100 nautical miles from the 2,500-meter isobath or a line 350 nautical miles from the baseline.

Field is an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or by both. The area may include one lease, a portion of a lease, or a group of leases with one or more wells that have been approved as producible.

[61] Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior

First purchase price is the actual amount paid by the first purchaser for crude oil as it leaves the lease on which it was produced.[62] A "first purchase" constitutes a transfer of ownership of crude oil during or immediately after the physical removal of the crude oil from a production property for the first time.

Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions.

Gravity Bands: The density of oil compared to the density of water, i.e., the specific gravity of the oil. The gravity is measured in degrees by the American Petroleum Institute (API). Oil with a low number is less valuable than with a high number. For example, oil is classified as light, medium or heavy, according to its measured API gravity. Light crude oil is defined as having an API gravity higher than 31.1°API. Medium oil is defined as having an API gravity between 22.3°API and 31.1°API. Heavy oil is defined as having an API gravity below 22.3°API.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in the gaseous, liquid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (methane, a constituent of natural gas) to the very heavy and very complex.

Lease: "Lease," as used in these standards, means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, extraction of, and/or removal of oil or gas.[63]

Lease condensate: A mixture consisting primarily of pentanes and heavier hydrocarbons which is recovered as a liquid from natural gas in lease separation facilities. This category excludes natural gas plant liquids, such as butane and propane, which are recovered at downstream natural gas processing plants or facilities.

Natural gas plant liquids (NGPLs): Those hydrocarbons in natural gas that are separated as liquids at natural gas processing plants, fractionating and cycling plants, and, in some instances, field facilities. Lease condensate is excluded. Products obtained include ethane; liquefied petroleum gases (propane, butanes, propane-butane mixtures, ethane-propane mixtures); isopentane; and other small quantities of finished products, such as motor gasoline, special naphthas, jet fuel, kerosene, and distillate fuel oil.

Oil: A mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities.

Oil Stream: Crude oil produced in a particular field or a collection of crude oils with similar qualities from fields in close proximity, which the petroleum industry usually describes with a specific name, such as West Texas Intermediate.

[62] EIA-182 Domestic Crude Oil First Purchase Report Instructions.
[63] 30 U.S.C. §1702 (5).

Outer Continental Shelf: The Federal Government administers the submerged lands, subsoil, and seabed lying between the seaward extent of the **States' jurisdiction** and the seaward extent of **Federal jurisdiction**.[64]

Play: A group of **pools** that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment.[65]

Pool: A discovered or undiscovered accumulation of hydrocarbons, typically within a single stratigraphic interval.[66]

Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves: The regional estimated quantities of proved oil and lease condensate reserves are those quantities of oil and lease condensate from Federal oil and gas resources that are totaled for a specified region. Quantities of oil and lease condensate are estimated in barrels (of 42 U.S. gallons) at 60 degrees Fahrenheit.

Regional Estimated Quantity of Proved Natural Gas Plant Liquids Reserves: The regional estimated quantities of proved natural gas plant liquids (NGPLs) reserves are those quantities of NGPLs from Federal gas resources that are totaled for a specified region. Quantities of NGPLs are estimated in barrels (of 42 U.S. gallons) at 60 degrees Fahrenheit.

Regional Estimated Quantity of Proved Gas Reserves: The regional estimated quantities of proved gas reserves are those quantities of dry gas from Federal gas resources that are totaled for a specified region. Quantities of gas are estimated in thousands of cubic feet (Mcf) at 14.73 PSIA67 and 60 degrees Fahrenheit.

Rent: A rent schedule is established at the time a lease is issued. Rents, as used in these standards, are annual payments, normally a fixed dollar amount per acre, required to preserve the rights to a lease while the lease is not in production.[68]

Reservoir: A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.[69]

Royalty: Royalty, as used in these standards, means any payment based on the value or volume of production which is due to the United States on production of oil, lease condensate, NGPLs, or gas

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[64] Glossary of Mineral Terms, Minerals Revenue Management, Mineral Management Service, U.S. Department of the Interior.
[65] Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior.
[66] Ibid.
[67] PSIA means pounds per square inch absolute. PSIA describes an absolute pressure per square inch that starts from a perfect vacuum. PSIA is influenced by weather and elevation. As a good frame of reference, there is 14.73-PSIA at sea level.
[68] Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior.
[69] Ibid.

from the Outer Continental Shelf or Federal lands, or any minimum royalty owed to the United States under any provision of a lease.[70]

Royalty rate: A proportionate interest in the production value of mineral deposits due the lessor from the lessee in accordance with a lease agreement.

Sales Value: The proceeds received for the sale of a product. Sales value is calculated by multiplying the sales volume by unit price.

Sales Volume: The volume, or quantity, of the product that is sold. The sales volume for gas is measured in thousand cubic feet (mcf) and in barrels (bbl) for oil, lease condensate and NGPLs.

States' jurisdiction is defined as follows:

- Texas and the Gulf coast of Florida are extended 3 marine leagues (9 nautical miles) seaward from the baseline from which the breadth of the territorial sea is measured.
- Louisiana is extended 3 imperial nautical miles (imperial nautical mile = 6080.2 feet) seaward of the baseline from which the breadth of the territorial sea is measured.
- All other States' seaward limits are extended 3 nautical miles (approximately 3.3 statute miles) seaward of the baseline from which the breadth of the territorial sea is measured.

Technically recoverable resources: For purposes of these standards, the term used to describe the total quantity of undiscovered recoverable resources and unproved reserves. Proved reserves are not included in the estimated quantity of technically recoverable resources.

Wellhead price is the value of the purchased natural gas at the mouth of the well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. Posted prices, requested prices, or prices as defined by lease agreements, contracts, or tax regulations should be used where applicable.[71]

[70] Adapted from 30 U.S.C. § 1702 (14).
[71] Energy Information Administration Glossary, http://www.eia.doe.gov/glossary/glossary_w.htm.

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