



April 9, 2009

Memorandum

To: Members of the Board
From:  Julia E. Ranagan, Assistant Director
Through:  Wendy M. Payne, Executive Director
Subj: Natural Resources – Tab F¹

OVERALL MEETING OBJECTIVE

The purpose of this 120 minute session is to reach consensus on the changes made [and not made] to the draft revised exposure draft (ED) on *Accounting for Federal Oil and Gas Resources* since the December 2008 board meeting so that staff can work towards a pre-ballot draft for the June 2009 board meeting.

SPECIFIC MEETING OBJECTIVES

Staff would specifically like to receive the board's response to the questions from the April staff discussion paper at **page 6**, the February staff discussion paper at **page 10**, and Issue Paper No. 7, Valuation Alternatives, at **page 14**.

BRIEFING MATERIAL

The following documents are attached to this transmittal memorandum:

- Attachment 1 – a staff discussion paper of the changes made to the revised exposure draft since the December 2008 board meeting beginning on page 4;
- Attachment 2 – the staff discussion paper from the February board binder of the changes made prior to the February board meeting beginning on page 7; and,
- Attachment 3 – Issue Paper No. 7, Valuation Alternatives, beginning on page 11.

In addition, the following materials are included in their respective tabs:

- Tab F-1 – Draft Revised ED, *Accounting for Federal Oil and Gas Resources*
- Tab F-2 – Natural Resources History of Project and Key Decisions

¹ The staff prepares Board meeting materials to facilitate discussion of issues at the Board meeting. This material is presented for discussion purposes only; it is not intended to reflect authoritative views of the FASAB or its staff. Official positions of the FASAB are determined only after extensive due process and deliberations.

In an effort to cut down on the amount and cost of duplicate material that is provided for each meeting, the following materials that have been provided in the past will be available at the board table in an individual binder for each member (as was done at the October and December board meetings):

- Task Force Discussion Paper, *Accounting for the Natural Resources of the Federal Government*, issued June 2000
- ED, *Accounting for Federal Oil and Gas Resources*, issued May 2007
- Comment Letters on ED
- Field Test Questionnaire Responses (in color to mark differences)
- Comparison of ED to Field Test Questionnaire Responses (in color to mark differences)

You may electronically access all of the briefing material at <http://www.fasab.gov/meeting.html> (the reference material is located at <http://www.fasab.gov/pdf/files/tabfnr/reference.pdf>).

NEXT STEPS

June 2009 Meeting

- Provide additional information on the fiduciary reporting requirement, if provided by DOI, to enable the board to reach consensus on whether to retain the recognition requirements as an integral part of the fiduciary activities Schedules of Fiduciary Activity and Net Assets.
- Provide additional information on how to treat custodial reporting for other commodities to enable the board to reach consensus on how the other commodities should be addressed in the interim until standards on all natural resources are issued.
- Provide a pre-ballot revised exposure draft that incorporates decisions from the April 2009 meeting.
- Provide a ballot draft that incorporates final member comments via email after the meeting.

July 2009

- Issue a revised exposure draft with comments due by late August / early September 2009.

October 2009 Meeting

- Discuss comments received on revised exposure draft.

December 2009 Meeting

- Finalize wording.
- Provide pre-ballot draft after meeting via email.

January 2010

- Provide ballot draft via email (will not be on February 2010 agenda if approved before meeting and there are no issues).
- Provide proposed standard to sponsors.

May 2010

- Issue final standard after sponsor review.

BACKGROUND

The May 2007 exposure draft (ED), *Accounting for Federal Oil and Gas Resources*, proposed accounting standards for federal oil and gas resources. 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” and would present the royalty share of the federal oil and gas resources classified as “proved reserves.” The asset’s value would be calculated by multiplying the estimated quantity of proved oil and lease condensate, natural gas plant liquids (NGPLs), 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. CBO believes that fair value is feasible and preferable. CBO’s alternative view proposed that fair value 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, e.g., 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, 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.

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 (fiscal year 2010), with early implementation permitted.

Based on the results of field testing and comments received from respondents, the Board is proposing several significant changes to the ED requirements discussed above which will require re-exposure.

See Tab F-2 for a timeline history of the project and key decisions since its original inception in May 1995.

If you require additional information or wish to suggest another alternative not considered in the staff paper, please contact me as soon as possible. Ideally, I would be able to respond to your request for information or develop more fully the alternative you wish considered in advance of the meeting. If you have any questions or comments prior to the meeting, please contact me by telephone at 202.512.7377 or by e-mail at ranaganj@fasab.gov.

Attachment

CHANGES MADE SINCE THE DECEMBER 2008 REVISED ED

In addition to the changes that were communicated in the February 2009 staff memorandum that were not discussed at the February meeting (see Attachment 2), the following changes have been made since the December 2008 revised ED:

1. **Revised paragraph 24 [from the February 2009 revised draft ED] to limit valuation alternatives to present value and fair value in accordance with the fair value hierarchy established in FAS 157, Fair Value Measurements.**

This change was made because there is considerable concern from at least two board members over the flexibility permitted by par. 24 regarding valuation alternatives and the related decision to transition the information from basic to RSI after a three-year period. Therefore, staff believes that the board has not reached consensus on this issue and has attempted to develop a solution by limiting the valuation alternatives to present value and fair value. See paragraph 24 in the revised draft ED at Tab F-1 for the revised requirements and Issue Paper No. 7 attached to this memorandum beginning on page 11 for further information and staff analysis.

2. **Incorporated board member comments on the February 2009 revised draft ED that were received prior to the February board meeting.**

Various editorial and other changes were made to incorporate comments on the February 2009 revised draft ED received from Messrs. Steinberg, Patton, and Jackson.

3. **Updated the basis for conclusions accordingly.**

CHANGE NOT MADE TO THE DECEMBER 2008 REVISED ED

In addition to the changes not made to the December 2008 ED that were communicated in the February 2009 staff memorandum (see Attachment 2), the following proposed change was **not** made to the February 2009 revised ED:

4. **Recognition of deferred revenue for the portion of estimated petroleum royalties to be distributed to federal entities.** Prior to the February board meeting at which natural resources was not discussed, Mr. Jackson informed staff that he thinks “the proposed oil and gas standard is flawed. Specifically, the second paragraph on page 3 of the Transmittal and page i (second paragraph) of the Executive Summary provide that ‘When oil and gas resources are extracted and royalties are earned, revenue and depletion expense equal to the earned revenue would be recognized by the federal government.’ However, paragraph 30 of the proposed standard provides that the cumulative net effect of recognizing an asset and establishing a liability to non-federal entities should be reflected as an increase in net position. Paragraph 38 compounds this problem because it calls for recognizing a gain or loss from annual valuation of estimated royalties. The problem is two fold. First and most importantly the standard should not provide for recognizing revenue and depletion expense until extraction. Second, the Executive Summary provides for that but the text of the standard provides for revenue recognition at the time of estimation or revaluation, not at the time of extraction. I am of the view that the

initial estimate should be recorded as an asset for the full amount of the estimate with a liability for amounts distributable to states and the difference recorded as deferred revenue.”

STAFF RESPONSE: “The asset that the government has with respect to the oil and gas natural resources is the actual oil and gas located under federal lands, not the royalties subsequently received once the oil has been produced. The asset already exists because the resources under the land already meet the SFFAC 5 definition of asset, which is “a resource that embodies economic benefits or services that the federal government controls,” whether or not the oil and gas is ever produced. The government can choose to hold onto the land (and the underlying resources), sell the land (which would purportedly receive a higher price to compensate for the associated natural resources) extract the resources itself (which it has done on occasion), donate the land, or lease the land to oil and gas producers and charge a royalty on production. The board has decided to value the asset (the actual oil and gas resources) by measuring the anticipated royalties to be received. The oil and gas resources could be valued any number of ways but under the principle of “highest and best intended use,” it is most likely that the government will lease the land and charge a royalty (and we are valuing the land that has already been leased since only proven reserves are being recognized). SFFAC 5 defines a revenue as “an inflow of or other increase in assets, a decrease in liabilities, or a combination of both that results in an increase in the government’s net position during the reporting period.” I conferred with Penny Wardlow (who developed SFFAC 5) and she stated that “The SFFAC 5 definition of revenue has no “earnings” concept and no distinction between an exchange and a non-exchange revenue. A revenue is basically an increase in net position resulting from an increase in assets, decrease in liabilities, or a combination of both.” Therefore, I believe the assets should flow through revenue when they are first recognized and revalued, because the asset already exists, it does not need to be earned. I believe you have correctly pointed out an inconsistency between SFFAC 5 and the proposed standard so I will need to scrub the ED to remove any misleading uses of the term “earned” and other related descriptive narratives.” – Mr. Jackson accepted this proposed resolution to his concern.

ISSUES NOT YET ADDRESSED

The following open issues from the December 2008 meeting still need to be addressed by staff and presented for board member consideration:

5. **Fiduciary disclosure requirements have not been addressed.** Despite repeated follow-up inquiries via telephone and email, staff has not received a response from DOI to enable the board to make an informed decision regarding cost/benefit. The DOI representative has indicated that this is a politically sensitive matter over which they are hesitant to respond. Staff proposes no changes to the current requirements at this time and will continue to seek a response to this issue.
6. **Accounting for other commodities has not been addressed.** Pending the outcome of decisions made at the April 2009 board meeting, staff will address this issue at the June 2009 board meeting.

QUESTION FOR THE BOARD MEMBERS

Do you object to any of the changes made [or not made] to the revised draft ED? If so, please explain the reasons for your objection and offer alternative solutions.

This is an excerpt from the February briefing materials, which were NOT discussed at the February board meeting due to the board’s primary focus on long-term projections and social insurance.

CHANGES MADE TO THE DECEMBER 2008 REVISED ED

The following changes were made to the December 2008 revised ED:

- 1. Revised paragraph 27 [from the December 2008 revised draft ED] to remove explicit reference to the formula [price X quantity X rate] as requested by a majority of the board members at the December 2008 meeting.**

This change was made at the request of the majority of the board members at the December 2008 meeting that the formula be removed from paragraph 27 and the language be softened [requested by Messrs. Torregrosa, Steinberg, Farrell, Jackson, Schumacher, and Allen]. See paragraph 24 in the revised draft ED at Tab F-1 for the revised language.

- 2. Deleted the proposed component entity RSI requirements in paragraphs 44a and 45 [from the December 2008 revised draft ED] and replaced them with requirements to present the major assumptions used to calculate the value of the federal government’s estimated petroleum royalties, explain the changes in the estimate from one year to the next, and reference the source reports used.**

This change was made because the original requirements were not supported by respondents to the ED. Furthermore, EIA has not provided the information necessary for the preparer to be able to present such information. See paragraph 43 in the revised draft ED at Tab F-1 for the revised requirements and Issue Paper No. 1 in Appendix 1 at Tab F-2 for further information and staff analysis.

- 3. Clarified that the liability for revenue distributions to others is a long-term liability and that the estimated portion of the liability to be distributed within 12 months of the fiscal year-end may be classified as current.**

This clarification was added at the request of DOI. See paragraphs 28 and 29 in the revised draft ED at Tab F-1 for the revised requirements and Issue Paper No. 3 in Appendix 1 at Tab F-2 for further information and staff analysis.

- 4. Clarified paragraph 28 [from the December 2008 revised draft ED] to require that a change in methodology be accounted for as a change in accounting estimate effected by a change in accounting principle.**

This change was made to address Mr. Farrell’s question of whether a change in methodology after the initial year of implementation should be treated as a change in principle rather than a change in estimate. Since changes in estimates are not explicitly addressed in FASAB standards,² staff adapted the guidance from SFAS 154,

² SFFAS 21, *Reporting Correction of Errors and Changes in Accounting Principles*, explicitly addresses corrections of errors and changes in principles. Indirect references to changes in estimate are made in SFFAC 5, footnote 10; SFFAS 6, pars. 99, 110, 190, and 191; Interpretation 4, par. 9; Technical Bulletin 2006-1, pars. 34 and 48; and Technical Release 2, par. 4.

Accounting Changes and Error Corrections (as amended), which defines a change in accounting estimate effected by a change in accounting principle as a change in accounting estimate that is inseparable from the effect of a related change in accounting principle. The financial statements of prior periods should not be restated for a change in accounting estimate. See paragraphs **24 – 26** and **A44** through **A47** in the revised draft ED at Tab F-1 for the revised requirements and discussion in the Basis for Conclusions.

- 5. Revised the liability recognition requirements in paragraphs 29 through 31 [from the December 2008 revised draft ED] so that only a liability for revenue to be distributed to non-federal entities (e.g., states) is required to be recognized.** A liability for revenue to be distributed to other federal entities is no longer required to be recognized. However, each federal receiving entity would disclose its relationship with the royalty revenue program and an estimate of the total amount of estimated petroleum royalties to be distributed to it in the notes to its financial statements.

This change was made based on the response to the field test questionnaire and a cost-benefit analysis. Staff believes that it is doubtful that the federal receiving entity management would find much decision-useful information with the recognition of a receivable that would be extremely volatile and could not be relied upon for short or long-term budget decisions. In addition, it is doubtful that the financial statement users would find more value in recognition of a receivable on the face of as opposed to in the notes to the financial statements. See paragraphs **27 – 30** and **A55** through **A59** in the revised draft ED at Tab F-1 for the revised requirements and discussion in the Basis for Conclusions, and Issue Paper No. 6 in Appendix 1 at Tab F-2 for further information and staff analysis.

- 6. Incorporated detailed requirements for reporting on changes in long-term assumptions based on guidance in SFFAS 33.**

As promised in par. 41 of the December 2008 draft of the revised ED, staff explored the need for additional guidance on what would constitute a change in assumption for oil and gas vs. true gains and losses by reviewing the requirements of SFFAS 33 and discussing changes in oil and gas estimates with DOI personnel. See paragraphs **42f** and **46** in the revised draft ED at Tab F-1 for the revised requirements and Issue Paper No. 5 in Appendix 1 at Tab F-2 for further information and staff analysis.

- 7. Incorporated accounting and disclosure requirements for the federal receiving entities.**

This change was made because Mr. Steinberg and the field test team pointed out that the pro forma transactions included entries for the federal entities that receive royalty distributions but receiving entity accounting and reporting requirements were not addressed in the standard itself. As noted in number 5 above, staff has proposed to eliminate the proposed recognition of a liability for other federal entities that was contained in the May 2007 ED. However, staff has recommended that the federal receiving entity disclose its relationship with the royalty revenue program and an estimate of the total amount of estimated petroleum royalties to be distributed to it in the notes to its financial statements. Staff also proposes adding the required accounting by the federal entities when royalty distributions are received. See paragraphs **44** and **45** in the revised draft ED at Tab F-1 for the new requirements.

8. Reinstated the detailed pro forma transactions and detail on how values were derived.

This change was made based on comments received from the field test team and Mr. Steinberg, indicating that the pro forma transactions did not provide enough detail to be useful. See Appendix C in the revised draft ED at Tab F-1.

9. Incorporated several minor edits from the field test team.

See Tab F-3 for Appendix 2, Summary of May 2007 ED Requirements and Recommended Response to Field Test Comments. This appendix includes a summary of the May 2007 ED requirements and the field test team's comments to both the ED and PV views along with a recommended response from staff.

10. Incorporated board member comments on the December 2008 revised draft ED.

Various editorial and other changes were made to incorporate comments on the December 2008 revised draft ED received from Messrs. Steinberg, Patton, and Farrell.

11. Updated the basis for conclusions accordingly.

CHANGES NOT MADE TO THE DECEMBER 2008 REVISED ED

The following requested changes were not made to the December 2008 revised ED:

12. Recognition of depletion expense in an amount equal to royalty revenue has not been changed. For a number of reasons, the DOI field test team requested depletion be recorded based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end (July through June). FASAB staff believes that the depletion approach in the ED was not devised to show the "true" effect on the asset during the period since the quantity gets adjusted again at year-end as part of the revaluation. Rather, the depletion approach was an attempt to ensure that the only bottom line effect on MMS' statement of net cost was the net gain / loss that resulted from quantity and value differences from one year to the next. In other words, the depletion approach in the ED is to "match" depletion expense with revenue recognition. Therefore, FASAB staff recommends retaining the current requirements related to depletion expense. See Issue Paper No. 4 in Appendix 1 at Tab F-2 for further information and staff analysis.

13. Recognition of gain / loss on the component entity's statement of net cost has not been changed. At the December 2008 board meeting, Mr. Jackson stated that he thinks it is inappropriate for the gains and losses on revaluation to show up on DOI's financial statements. He sees where the gains and losses recognized on the statement of net cost are offset by a transfer out on the statement of changes in net position, but he does not believe that the agency should be saddled with reporting those gains and losses since they are not true gains and losses for DOI. Based on staff's understanding of Statement of Federal Financial Accounting Concepts 5, *Definition of Elements and Basic Recognitions Criteria for Accrual-Basis Financial Statements*, and the intent of the board when developing that statement, staff believes it is appropriate for the gains and losses from revaluation of estimated petroleum royalties to be reported in the statement

of net cost of DOI because they are the component entity most closely responsible for managing royalty revenue. Therefore, FASAB staff recommends retaining the requirement that gains and losses from revaluation of estimated petroleum royalties be reported in the statement of net cost of DOI. See Issue Paper No. 6 in Appendix 1 at Tab F-2 for further information and staff analysis.

ISSUES NOT YET ADDRESSED

The following open issues from the December 2008 meeting still need to be addressed by staff and presented for board member consideration:

- 14. Fiduciary disclosure requirements have not been addressed.** Staff has not received a response from DOI to enable the board to make an informed decision regarding cost/benefit. See Issue Paper No. 2 in Appendix 1 at Tab F-2 for further information and staff analysis. Staff proposes no changes to the current requirements at this time and will continue to seek a response to this issue.

- 15. Accounting for other commodities has not been addressed.** Staff will address this issue at the April 2009 board meeting.

QUESTION FOR THE BOARD MEMBERS

Do you object to any of the changes made [or not made] to the revised draft ED? If so, please explain the reasons for your objection and offer alternative solutions.

Issue Paper No. 7: Valuation Alternatives

December 2008 Draft ED Requirements

The December 2008 draft of the revised exposure draft (ED) on *Accounting for Federal Oil and Gas Resources* contained the following proposed requirements related to an alternative valuation method if present value is not reasonably possible:

27. If it is not reasonably possible to estimate the present value of future federal royalty receipts on proved reserves, then the value of the federal government's estimated petroleum royalties may be computed by multiplying the estimated quantity of proved oil and gas reserves under federal lands by the average first purchase price for oil or average wellhead price for gas and the effective average royalty rate by region. Other methodologies may be acceptable.

Board Member Concern about December Draft ED Requirements Regarding Alternative Valuation

At the December 2008 board meeting, a majority of the board members [Messrs. Torregrosa, Steinberg, Farrell, Jackson, Schumacher, and Allen] requested that staff remove the explicit reference to the formula [price X quantity X rate] and soften the language to allow more flexibility. Messrs. Patton, Werfel, and Dacey expressed concern that the valuation method and alternatives should be explicit if the information is to be reported as basic information; otherwise, the information should remain as RSI indefinitely.

February 2009 Draft ED Requirements

At the request of the majority of the board members as the December 2008 meeting, staff proposed the following changes to the ED:

- ~~27-24. The preferred measurement method for valuing the federal government's estimated petroleum royalties is the present value of future federal royalty receipts on proved reserves; however, another methodology may be acceptable if it is not reasonably possible to estimate the present value of future federal royalty receipts on proved reserves, then the value of the federal government's estimated petroleum royalties may be computed by multiplying the estimated quantity of proved oil and gas reserves under federal lands by the average first purchase price for oil or average wellhead price for gas and the effective average royalty rate by region. Other methodologies may be acceptable.~~

Board Member Concern about February Draft ED Requirements Regarding Alternative Valuation

Due to the board's focus on long-term projections and social insurance, the revised ED was not discussed at the February meeting. However, prior to the meeting, Mr. Patton communicated to staff that he still had significant concerns about the valuation flexibility allowed by Paragraph 24,

especially after the three-year period when the reporting will reach the “basic” stage. He said he would prefer that the effective date section say that the information would remain RSI *until* the Board says otherwise instead of having the information transition to “basic” *unless* the Board says otherwise. That would force the Board to examine the results of the initial efforts at valuation and reporting before proceeding to “basic.” He said, at that point, he would hope/ expect that the Board would have enough evidence to decide whether the PV approach is relevant/reliable enough to prescribe it and omit the open-ended “another methodology may be acceptable” option.

FASAB Staff Analysis and Recommendation

A majority of the board members voted to retain the requirement in the ED that the information transition from RSI to basic after a three-year period. The members felt that it was important to have a date certain to ensure that audit requirements would be developed in a timely manner. Therefore, staff conferred on ways to allow for some flexibility, while addressing concerns about having “open-ended” methodologies. Staff is recommending that the board adopt the FAS 157, *Fair Value Measurements*, approach, as discussed below (see the attachment to this issue paper for an excerpt of the FAS 157 summary and standards sections).

FAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. FAS 157 provides for increased consistency and comparability in fair value measurements.

Based on the results of DOI’s field testing of the May 2007 ED, members selected present value as the preferred measurement method for valuing the federal government’s estimated petroleum royalties. Present value is a method for measuring fair value if the approach approximates an exit value; there are other methods that can be used to measure fair value.

FAS 157 defines fair value as 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 (par. 5). In applying FAS 157 to assets, FASB notes that a fair value measurement assumes the highest and best use of the asset by market participants, considering the use of the asset that is physically possible, legally permissible, and financially feasible at the measurement date (FAS 157, par. 12).

To increase consistency and comparability in fair value measurements and related disclosures, FAS 157 utilizes a fair value hierarchy that priorities the inputs to valuation techniques used to measure fair value into three broad levels. The FAS 157 fair value hierarchy gives the highest priority to quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (FAS 157, pars. 22 and 28).

In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The level in the fair value hierarchy within which the fair value measurement in its entirety falls shall be determined based on the lowest level input that is significant to the fair value measurement in its entirety (FAS 157, par. 22).

While Level 1 is preferred, oil and gas inputs (for the most part) would likely be considered “Level 3 Inputs” on the FAS 157 fair value hierarchy. FAS 157 defines level 3 inputs as unobservable inputs for the asset or liability. FAS 157 notes that unobservable inputs should be used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. However, the fair value measurement objective remains the same, that is, an exit price from the perspective of a market participant that holds the asset or owes the liability. Therefore, unobservable inputs should reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk) (FAS 157, par. 30).

FAS 157 states that unobservable inputs should be developed based on the best information available in the circumstances, which might include the reporting entity's own data. In developing unobservable inputs, the reporting entity need not undertake all possible efforts to obtain information about market participant assumptions. However, the reporting entity shall not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Therefore, the reporting entity's own data used to develop unobservable inputs should be adjusted if information is reasonably available without undue cost and effort that indicates that market participants would use different assumptions (FAS 157, par. 30).

FAS 157 states that, for assets and liabilities that are measured at fair value on a recurring basis in periods subsequent to initial recognition (for example, trading securities), the reporting entity should disclose information that enables users of its financial statements to assess the inputs used to develop those measurements and for recurring fair value measurements using significant unobservable inputs (Level 3), the effect of the measurements on earnings (or changes in net assets) for the period. FAS 157 includes several disclosures that help entities meet that objective (FAS 157, par. 32).

Recommendation: In order to provide the preparer with some level of flexibility while still maintaining a specific requirement (fair value), staff proposes that the following changes be incorporated into the ED:

24. The preferred measurement method for valuing the federal government’s estimated petroleum royalties is the present value of future federal royalty receipts on proved reserves as provided in par. 20 through 23; however, ~~another methodologys for~~ measuring fair value may be acceptable if it is not reasonably possible to estimate present value. ^[FN]

^[FN] FAS 157, *Fair Value Measurements*, provides a framework for measuring fair value.

Request for Board to Reaffirm Decision

Staff is proposing this recommendation because there is considerable concern from at least two board members over the flexibility permitted by par. 24 regarding valuation alternatives and the related decision to transition the information from basic to RSI after a three-year period. Therefore, staff believes that the board has not reached consensus on this issue and is attempting to develop a solution by limiting the valuation alternatives to fair value.

While the board originally rejected fair value during development of the May 2007 ED, it has since accepted DOI's proposed present value approach. Present value is one method for measuring fair value. However, the approach proposed in the ED requires use of an entity specific discount rate – the risk free rate – and not a market rate. The entity specific rate is not consistent with an exit value and is therefore not entirely consistent with the FAS 157 definition of fair value. However, staff believes that the FAS 157 hierarchy would provide a reasonable alternative if present value is not reasonably determinable.

There is some concern that the final valuation method that is proposed by DOI may, for various reasons, differ from both the present value approach proposed and the FAS 157 alternative. Therefore, the RSI would either not be presented (because fair value was not determinable), or presented on a verifiable basis other than fair value. In either case, it would affect the audit report as RSI and even more so as basic. That was the reasoning behind providing for flexibility in the method used.

The primary reason the board voted to move to basic after a three-year transition period was because the information was deemed to be of primary importance and a date certain was necessary in order to get the audit community to develop audit requirements in a timely manner.

Therefore, because of the lack of consensus (meaning at least two board members cannot live with the broad flexibility/movement to basic status), staff believes that the board members may desire to reaffirm their decision.

- 1. Do you agree with staff's proposal to limit the valuation alternatives to present value and fair value?**
- 2. If you do not agree with staff's proposal, do you support the broad flexibility that was originally provided by the February 2009 revised ED?**
- 3. Do you support the transition from RSI to basic after a specified period of time (e.g., three years) for both (a) staff's recommendation to limit the valuation alternatives to present value and fair value and (b) broad valuation flexibility?**

Checkpoint Contents

Accounting, Audit & Corporate Finance Library

Standards and Regulations

FASB

Original Pronouncements, as amended, including Implementation Guides and FASB Staff Positions

FASB Statements (FAS)

FAS 157: Fair Value Measurements (as amended)

Copyright © 2009 by Financial Accounting Standards Board, Norwalk, Connecticut

Fair Value Measurements (as amended)

Status

Issued: September 2006

Effective Date:

For financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years

[Related document(s):

IAS 37]

Affects:

Amends APB 21, paragraphs 13 and 18
Deletes APB 21, footnote 1
Amends APB 28, paragraph 30
Amends APB 29, paragraphs 18 and 20(a)
Deletes APB 29, paragraph 25 and footnote 5
Amends FAS 13, paragraph 5(c)
Amends FAS 15, paragraphs 13 and 28
Deletes FAS 15, footnotes 2, 5a, and 6
Amends FAS 19, paragraph 47(l)(i)
Amends FAS 35, paragraph 11 and footnote 5
Deletes FAS 35, footnote 4a
Amends FAS 60, paragraph 19
Deletes FAS 60, footnote 4a
Amends FAS 63, paragraphs 4, 8, and 38 through 40
Amends FAS 65, paragraphs 4, 6, 9, 10, 12, and 29
Amends FAS 67, paragraphs 8 and 28
Deletes FAS 67, footnote 6
Amends FAS 87, paragraphs 49 and 264 and footnote 12
Deletes FAS 87, footnote 11a
Amends FAS 106, paragraphs 65 and 518 and footnote 21
Deletes FAS 106, footnote 20a
Deletes FAS 107, paragraphs 5, 6, 11, and 18 through 29
Amends FAS 107, paragraphs 9, 10, 30, and 31
Amends FAS 115, paragraphs 3(a) and 137
Replaces FAS 115, footnote 2
Amends FAS 116, paragraphs 19, 20, 184, 186, and 208
Deletes FAS 116, footnote 8
Amends FAS 124, paragraphs 3(a) and 112
Replaces FAS 124, footnote 3
Deletes FAS 133, paragraph 16A and footnote 6c

Amends FAS 133, paragraphs 17 and 540
Effectively deletes FAS 133, footnotes 9b, 10b, 18a, 18b, 20a through 20e, and 24a
Amends FAS 136, Summary and paragraphs 15 and 36
Amends FAS 140, paragraphs 11(c), 17(h), 17(i), 63(b), and 364
Deletes FAS 140, paragraphs 68 through 70 and footnotes 20 and 21
Amends FAS 141, paragraph F1
Amends FAS 142, paragraphs 3, 19, 23, and F1
Deletes FAS 142, paragraphs 24, E1, and E2 and footnotes 12 and 16
Deletes FAS 143, paragraphs 6, 7, 9, A19, and F1 through F4 and footnotes 5, 6, 7, 8, 17, and 19
Amends FAS 143, paragraphs 8, A20, A21, A26, C1, C3(d), C4, C6 through C9, C11, and C12 and footnotes 12 and 18
Deletes FAS 144, paragraphs 22, 24, A12, and E1 through E3 and footnotes 12 through 14, 28, and 29
Deletes FAS 146, paragraphs 5, A4, and A5 and footnotes 13 through 16
Amends FAS 146, paragraph A2
Amends FAS 150, paragraph D1
Deletes FAS 156, paragraph 3(c)
Amends FIN 45, paragraphs 9(a) and 9(b)

Affected by:

Paragraph 2 amended by FSP FAS 157-1, paragraph 9(a)

Paragraph 36 amended by FSP FAS 157-2, paragraph 11

Paragraph D1 amended by FSP FAS 157-1, paragraph 9(b)

Footnote 2 amended by FAS 141(R), paragraph E4(a)

Other Interpretive Releases: FASB Staff Positions FAS 157-1 and FAS 157-2

Issues Discussed by FASB Emerging Issues Task Force (EITF)

Affects:

Modifies EITF Issue No 02-3

Interpreted by:

No EITF Issues

Related Issues:

No EITF Issues

Summary

This Statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements, the Board having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, this Statement does not require any new fair value measurements. However, for some entities, the application of this Statement will change current practice.

Reason for Issuing This Statement

Prior to this Statement, there were different definitions of fair value and limited guidance for applying those definitions in GAAP. Moreover, that guidance was dispersed among the many accounting pronouncements that require fair value measurements. Differences in that guidance created inconsistencies that added to the complexity in applying GAAP. In developing this Statement, the Board considered the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements.

Differences between This Statement and Current Practice

The changes to current practice resulting from the application of this Statement relate to the definition of fair value, the methods used to measure fair value, and the expanded disclosures about fair value measurements.

The definition of fair value retains the exchange price notion in earlier definitions of fair value. This Statement clarifies that the exchange price is the price in an orderly transaction between market participants to sell the asset or transfer the liability in the market in which the reporting entity would transact for the asset or liability, that is, the principal or most advantageous market for the asset or liability. The transaction to sell the asset or transfer the liability is a hypothetical transaction at the measurement date, considered from the perspective of a market participant that holds the asset or owes the liability. Therefore, the definition focuses on the price that would be received to sell the asset or paid to transfer the liability (an exit price), not the price that would be paid to acquire the asset or received to assume the liability (an entry price).

This Statement emphasizes that fair value is a market-based measurement, not an entity-specific measurement. Therefore, a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability. As a basis for considering market participant assumptions in fair value measurements, this Statement establishes a fair value hierarchy that distinguishes

between (1) market participant assumptions developed based on market data obtained from sources independent of the reporting entity (observable inputs) and (2) the reporting entity's own assumptions about market participant assumptions developed based on the best information available in the circumstances (unobservable inputs). The notion of unobservable inputs is intended to allow for situations in which there is little, if any, market activity for the asset or liability at the measurement date. In those situations, the reporting entity need not undertake all possible efforts to obtain information about market participant assumptions. However, the reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort.

This Statement clarifies that market participant assumptions include assumptions about risk, for example, the risk inherent in a particular valuation technique used to measure fair value (such as a pricing model) and/or the risk inherent in the inputs to the valuation technique. A fair value measurement should include an adjustment for risk if market participants would include one in pricing the related asset or liability, even if the adjustment is difficult to determine. Therefore, a measurement (for example, a "mark-to-model" measurement) that does not include an adjustment for risk would not represent a fair value measurement if market participants would include one in pricing the related asset or liability.

This Statement clarifies that market participant assumptions also include assumptions about the effect of a restriction on the sale or use of an asset. A fair value measurement for a restricted asset should consider the effect of the restriction if market participants would consider the effect of the restriction in pricing the asset. That guidance applies for stock with restrictions on sale that terminate within one year that is measured at fair value under FASB Statements No. 115, Accounting for Certain Investments in Debt and Equity Securities, and No. 124, Accounting for Certain Investments Held by Not-for-Profit Organizations.

This Statement clarifies that a fair value measurement for a liability reflects its nonperformance risk (the risk that the obligation will not be fulfilled). Because nonperformance risk includes the reporting entity's credit risk, the reporting entity should consider the effect of its credit risk (credit standing) on the fair value of the liability in all periods in which the liability is measured at fair value under other accounting

pronouncements, including FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities.

This Statement affirms the requirement of other FASB Statements that the fair value of a position in a financial instrument (including a block) that trades in an active market should be measured as the product of the quoted price for the individual instrument times the quantity held (within Level 1 of the fair value hierarchy). The quoted price should not be adjusted because of the size of the position relative to trading volume (blockage factor). This Statement extends that requirement to broker-dealers and investment companies within the scope of the AICPA Audit and Accounting Guides for those industries.

This Statement expands disclosures about the use of fair value to measure assets and liabilities in interim and annual periods subsequent to initial recognition. The disclosures focus on the inputs used to measure fair value and for recurring fair value measurements using significant unobservable inputs (within Level 3 of the fair value hierarchy), the effect of the measurements on earnings (or changes in net assets) for the period. This Statement encourages entities to combine the fair value information disclosed under this Statement with the fair value information disclosed under other accounting pronouncements, including FASB Statement No. 107, Disclosures about Fair Value of Financial Instruments, where practicable.

The guidance in this Statement applies for derivatives and other financial instruments measured at fair value under Statement 133 at initial recognition and in all subsequent periods. Therefore, this Statement nullifies the guidance in footnote 3 of EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." This Statement also amends Statement 133 to remove the similar guidance to that in Issue 02-3, which was added by FASB Statement No. 155, Accounting for Certain Hybrid Financial Instruments.

How the Conclusions in This Statement Relate to the FASB's Conceptual Framework

The framework for measuring fair value considers the concepts in FASB Concepts Statement No. 2, Qualitative Characteristics of Accounting Information. Concepts Statement 2 emphasizes that providing comparable information enables users of financial statements to identify similarities in and differences between two sets of economic events.

The definition of fair value considers the concepts relating to assets and liabilities in FASB Concepts Statement No. 6, Elements of Financial Statements, in the context of market participants. A fair value measurement reflects current market participant assumptions about the future inflows associated with an asset (future economic benefits) and the future outflows associated with a liability (future sacrifices of economic benefits).

This Statement incorporates aspects of the guidance in FASB Concepts Statement No. 7, Using Cash Flow Information and Present Value in Accounting Measurements, as clarified and/or reconsidered in this Statement. This Statement does not revise Concepts Statement 7. The Board will consider the need to revise Concepts Statement 7 in its conceptual framework project.

The expanded disclosures about the use of fair value to measure assets and liabilities should provide users of financial statements (present and potential investors, creditors, and others) with information that is useful in making investment, credit, and similar decisions—the first objective of financial reporting in FASB Concepts Statement No. 1, Objectives of Financial Reporting by Business Enterprises.

How the Changes in This Statement Improve Financial Reporting

A single definition of fair value, together with a framework for measuring fair value, should result in increased consistency and comparability in fair value measurements.

The expanded disclosures about the use of fair value to measure assets and liabilities should provide users of financial statements with better information about the extent to which fair value is used to measure recognized assets and liabilities, the inputs used to develop the measurements, and the effect of certain of the measurements on earnings (or changes in net assets) for the period.

The expanded disclosures about the use of fair value to measure assets and liabilities should provide users of financial statements with better information about the extent to which fair value is used to measure recognized assets and liabilities, the inputs used to develop the measurements, and the effect of certain of the measurements on earnings (or changes in net assets) for the period.

Costs and Benefits of Applying This Statement

The framework for measuring fair value builds on current practice and requirements. However, some entities will need to make systems and other changes to comply with the requirements of this Statement. Some entities also might incur incremental costs in applying the requirements of this Statement. However, the benefits from increased consistency and comparability in fair value measurements and expanded disclosures about those measurements should be ongoing.

The Effective Date of This Statement

This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including financial statements for an interim period within that fiscal year.

The provisions of this Statement should be applied prospectively as of the beginning of the fiscal year in which this Statement is initially applied, except as follows. The provisions of this Statement should be applied retrospectively to the following financial instruments as of the beginning of the fiscal year in which this Statement is initially applied (a limited form of retrospective application):

- a. A position in a financial instrument that trades in an active market held by a broker-dealer or investment company within the scope of the AICPA Audit and Accounting Guides for those industries that was measured at fair value using a blockage factor prior to initial application of this Statement
- b. A financial instrument that was measured at fair value at initial recognition under Statement 133 using the transaction price in accordance with the guidance in footnote 3 of Issue 02-3 prior to initial application of this Statement
- c. A hybrid financial instrument that was measured at fair value at initial recognition under Statement 133 using the transaction price in accordance with the guidance in Statement 133 (added by Statement 155) prior to initial application of this Statement.

The transition adjustment, measured as the difference between the carrying amounts and the fair values of those financial instruments at the date this Statement is initially applied, should be recognized as a cumulative-effect adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for the fiscal year in which this Statement is initially applied.

Statement of Financial Accounting Standards No. 157

Fair Value Measurements

September 2006

CONTENTS	Paragraph Numbers
Objective	1
Standards of Financial Accounting and Reporting:	
Scope	2-4
Measurement	5-31
Definition of Fair Value	5-15

The Asset or Liability	6
The Price	7
The Principal (or Most Advantageous) Market	8- 9
Market Participants	10-11
Application to Assets	12-14
Application to Liabilities	15
Fair Value at Initial Recognition	16-17
Valuation Techniques	18-20
Inputs to Valuation Techniques	21
Fair Value Hierarchy	22-31
Level 1 Inputs	24-27
Level 2 Inputs	28-29
Level 3 Inputs	30
Inputs Based on Bid and Ask Prices	31
Disclosures	32-35
Effective Date and Transition	36-39
Appendix A: Implementation Guidance	A1-A36
Appendix B: Present Value Techniques	B1-B19
Appendix C: Background Information and Basis for Conclusions	C1-C116
Appendix D: References to APB and FASB Pronouncements	D1
Appendix E: Amendments to APB and FASB Pronouncements	E1-E32

OBJECTIVE

1. This Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. Where applicable, this Statement simplifies and codifies related guidance within generally accepted accounting principles (GAAP).

STANDARDS OF FINANCIAL ACCOUNTING AND REPORTING

Scope

2. This Statement applies under other accounting pronouncements ¹ that require or permit fair value measurements, except as follows:

- a. This Statement does not apply under accounting pronouncements that address share-based payment transactions: FASB Statement No. 123 (revised 2004), Share-Based Payment, and its related interpretive accounting pronouncements that address share-based payment transactions.
- b. This Statement does not eliminate the practicability exceptions to fair value measurements in accounting pronouncements within the scope of this Statement. ²
- c. This Statement does not apply under FASB Statement No. 13, Accounting for Leases, and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under Statement 13. This scope exception does not apply to assets acquired and liabilities assumed in a business combination that are required to be measured at fair value under Statement 141 or Statement 141(R), regardless of whether those assets and liabilities are related to leases.

3. This Statement does not apply under accounting pronouncements that require or permit

measurements that are similar to fair value but that are not intended to measure fair value, including the following:

- a. Accounting pronouncements that permit measurements that are based on, or otherwise use, vendor-specific objective evidence of fair value³
- b. ARB No. 43, Chapter 4, "Inventory Pricing."

4. Appendix D lists pronouncements of the Accounting Principles Board (APB) and the FASB existing at the date of this Statement that are within the scope of this Statement. Appendix E lists those APB and FASB pronouncements that are amended by this Statement.

Measurement

Definition of Fair Value

5. 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.

The Asset or Liability

6. A fair value measurement is for a particular asset or liability.⁴ Therefore, the measurement should consider attributes specific to the asset or liability, for example, the condition and/or location of the asset or liability and restrictions, if any, on the sale or use of the asset at the measurement date. The asset or liability might be a standalone asset or liability (for example, a financial instrument or an operating asset) or a group of assets and/or liabilities (for example, an asset group, a reporting unit, or a business). Whether the asset or liability is a standalone asset or liability or a group of assets and/or liabilities depends on its unit of account. The unit of account determines what is being measured by reference to the level at which the asset or liability is aggregated (or disaggregated) for purposes of applying other accounting pronouncements. The unit of account for the asset or liability should be determined in accordance with the provisions of other accounting pronouncements, except as provided in paragraph 27.

The Price

7. A fair value measurement assumes that the asset or liability is exchanged in an orderly transaction between market participants to sell the asset or transfer the liability at the measurement date. An orderly transaction is a transaction that assumes exposure to the market for a period prior to the measurement date to allow for marketing activities that are usual and customary for transactions involving such assets or liabilities; it is not a forced transaction (for example, a forced liquidation or distress sale). The transaction to sell the asset or transfer the liability is a hypothetical transaction at the measurement date, considered from the perspective of a market participant that holds the asset or owes the liability. Therefore, the objective of a fair value measurement is to determine the price that would be received to sell the asset or paid to transfer the liability at the measurement date (an exit price).

The Principal (or Most Advantageous) Market

8. A fair value measurement assumes that the transaction to sell the asset or transfer the liability occurs in the principal market for the asset or liability or, in the absence of a principal market, the most advantageous market for the asset or liability. The principal market is the market in which the reporting entity would sell the asset or transfer the liability with the greatest volume and level of activity for the asset or liability. The most advantageous market is the market in which the reporting entity would sell the asset or transfer the liability with the price that maximizes the amount that would be received for the asset or minimizes the amount that would be paid to transfer the liability, considering transaction costs in the respective market(s). In either case, the principal (or most advantageous) market (and thus, market participants) should be considered from the perspective of the reporting entity, thereby allowing for differences between and among entities with different activities. If there is a principal market for the asset or liability, the fair value measurement shall represent the price in that market (whether that price

is directly observable or otherwise determined using a valuation technique), even if the price in a different market is potentially more advantageous at the measurement date.

9. The price in the principal (or most advantageous) market used to measure the fair value of the asset or liability shall not be adjusted for transaction costs.⁵ Transaction costs represent the incremental direct costs to sell the asset or transfer the liability in the principal (or most advantageous) market for the asset or liability.⁶ Transaction costs are not an attribute of the asset or liability; rather, they are specific to the transaction and will differ depending on how the reporting entity transacts. However, transaction costs do not include the costs that would be incurred to transport the asset or liability to (or from) its principal (or most advantageous) market. If location is an attribute of the asset or liability (as might be the case for a commodity), the price in the principal (or most advantageous) market used to measure the fair value of the asset or liability shall be adjusted for the costs, if any, that would be incurred to transport the asset or liability to (or from) its principal (or most advantageous) market.

Market Participants

10. Market participants are buyers and sellers in the principal (or most advantageous) market for the asset or liability that are:

- a. Independent of the reporting entity; that is, they are not related parties⁷
- b. Knowledgeable, having a reasonable understanding about the asset or liability and the transaction based on all available information, including information that might be obtained through due diligence efforts that are usual and customary
- c. Able to transact for the asset or liability
- d. Willing to transact for the asset or liability; that is, they are motivated but not forced or otherwise compelled to do so.

11. The fair value of the asset or liability shall be determined based on the assumptions that market participants would use in pricing the asset or liability. In developing those assumptions, the reporting entity need not identify specific market participants. Rather, the reporting entity should identify characteristics that distinguish market participants generally, considering factors specific to (a) the asset or liability, (b) the principal (or most advantageous) market for the asset or liability, and (c) market participants with whom the reporting entity would transact in that market.

Application to Assets

12. A fair value measurement assumes the highest and best use of the asset by market participants, considering the use of the asset that is physically possible, legally permissible, and financially feasible at the measurement date. In broad terms, highest and best use refers to the use of an asset by market participants that would maximize the value of the asset or the group of assets within which the asset would be used. Highest and best use is determined based on the use of the asset by market participants, even if the intended use of the asset by the reporting entity is different.

13. The highest and best use of the asset establishes the valuation premise used to measure the fair value of the asset. Specifically:

- a. *In-use*. The highest and best use of the asset is in-use if the asset would provide maximum value to market participants principally through its use in combination with other assets as a group (as installed or otherwise configured for use). For example, that might be the case for certain nonfinancial assets. If the highest and best use of the asset is in-use, the fair value of the asset shall be measured using an in-use valuation premise. When using an in-use valuation premise, the fair value of the asset is determined based on the price that would be received in a current transaction to sell the asset assuming that the asset would be used with other assets as a group and that those assets would be available to market participants. Generally, assumptions about the highest and best use of the asset should be consistent for all of the assets of the group within which it would be used.
- b. *In-exchange*. The highest and best use of the asset is in-exchange if the asset would provide

maximum value to market participants principally on a standalone basis. For example, that might be the case for a financial asset. If the highest and best use of the asset is in-exchange, the fair value of the asset shall be measured using an in-exchange valuation premise. When using an in-exchange valuation premise, the fair value of the asset is determined based on the price that would be received in a current transaction to sell the asset standalone.

14. Because the highest and best use of the asset is determined based on its use by market participants, the fair value measurement considers the assumptions that market participants would use in pricing the asset, whether using an in-use or an in-exchange valuation premise. [8](#)

Application to Liabilities

15. A fair value measurement assumes that the liability is transferred to a market participant at the measurement date (the liability to the counterparty continues; it is not settled) and that the nonperformance risk relating to that liability is the same before and after its transfer. Nonperformance risk refers to the risk that the obligation will not be fulfilled and affects the value at which the liability is transferred. Therefore, the fair value of the liability shall reflect the nonperformance risk relating to that liability. Nonperformance risk includes but may not be limited to the reporting entity's own credit risk. The reporting entity shall consider the effect of its credit risk (credit standing) on the fair value of the liability in all periods in which the liability is measured at fair value. That effect may differ depending on the liability, for example, whether the liability is an obligation to deliver cash (a financial liability) or an obligation to deliver goods or services (a nonfinancial liability), and the terms of credit enhancements related to the liability, if any.

Fair Value at Initial Recognition

16. When an asset is acquired or a liability is assumed in an exchange transaction for that asset or liability, the transaction price represents the price paid to acquire the asset or received to assume the liability (an entry price). In contrast, the fair value of the asset or liability represents the price that would be received to sell the asset or paid to transfer the liability (an exit price). Conceptually, entry prices and exit prices are different. Entities do not necessarily sell assets at the prices paid to acquire them. Similarly, entities do not necessarily transfer liabilities at the prices received to assume them.

17. In many cases, the transaction price will equal the exit price and, therefore, represent the fair value of the asset or liability at initial recognition. In determining whether a transaction price represents the fair value of the asset or liability at initial recognition, the reporting entity shall consider factors specific to the transaction and the asset or liability. For example, a transaction price might not represent the fair value of an asset or liability at initial recognition if:

- a. The transaction is between related parties.
- b. The transaction occurs under duress or the seller is forced to accept the price in the transaction. For example, that might be the case if the seller is experiencing financial difficulty.
- c. The unit of account represented by the transaction price is different from the unit of account for the asset or liability measured at fair value. For example, that might be the case if the asset or liability measured at fair value is only one of the elements in the transaction, the transaction includes unstated rights and privileges that should be separately measured, or the transaction price includes transaction costs.
- d. The market in which the transaction occurs is different from the market in which the reporting entity would sell the asset or transfer the liability, that is, the principal or most advantageous market. For example, those markets might be different if the reporting entity is a securities dealer that transacts in different markets, depending on whether the counterparty is a retail customer (retail market) or another securities dealer (inter-dealer market).

Valuation Techniques

18. Valuation techniques consistent with the market approach, income approach, and/or cost approach shall be used to measure fair value. Key aspects of those approaches are summarized below:

a. *Market approach.* The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities (including a business). For example, valuation techniques consistent with the market approach often use market multiples derived from a set of comparables. Multiples might lie in ranges with a different multiple for each comparable. The selection of where within the range the appropriate multiple falls requires judgment, considering factors specific to the measurement (qualitative and quantitative). Valuation techniques consistent with the market approach include matrix pricing. Matrix pricing is a mathematical technique used principally to value debt securities without relying exclusively on quoted prices for the specific securities, but rather by relying on the securities' relationship to other benchmark quoted securities.

b. *Income approach.* The income approach uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts. Those valuation techniques include present value techniques; option-pricing models, such as the Black-Scholes- Merton formula (a closed-form model) and a binomial model (a lattice model), which incorporate present value techniques;⁹ and the multiperiod excess earnings method, which is used to measure the fair value of certain intangible assets.¹⁰

c. *Cost approach.* The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (often referred to as current replacement cost). From the perspective of a market participant (seller), the price that would be received for the asset is determined based on the cost to a market participant (buyer) to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence. Obsolescence encompasses physical deterioration, functional (technological) obsolescence, and economic (external) obsolescence and is broader than depreciation for financial reporting purposes (an allocation of historical cost) or tax purposes (based on specified service lives).

19. Valuation techniques that are appropriate in the circumstances and for which sufficient data are available shall be used to measure fair value. In some cases, a single valuation technique will be appropriate (for example, when valuing an asset or liability using quoted prices in an active market for identical assets or liabilities). In other cases, multiple valuation techniques will be appropriate (for example, as might be the case when valuing a reporting unit). If multiple valuation techniques are used to measure fair value, the results (respective indications of fair value) shall be evaluated and weighted, as appropriate, considering the reasonableness of the range indicated by those results. A fair value measurement is the point within that range that is most representative of fair value in the circumstances.

20. Valuation techniques used to measure fair value shall be consistently applied. However, a change in a valuation technique or its application (for example, a change in its weighting when multiple valuation techniques are used) is appropriate if the change results in a measurement that is equally or more representative of fair value in the circumstances. That might be the case if, for example, new markets develop, new information becomes available, information previously used is no longer available, or valuation techniques improve. Revisions resulting from a change in the valuation technique or its application shall be accounted for as a change in accounting estimate (FASB Statement No. 154, *Accounting Changes and Error Corrections*, paragraph 19). The disclosure provisions of Statement 154 for a change in accounting estimate are not required for revisions resulting from a change in a valuation technique or its application.

Inputs to Valuation Techniques

21. In this Statement, *inputs* refer broadly to the assumptions that market participants would use in pricing the asset or liability, including assumptions about risk, for example, the risk inherent in a particular valuation technique used to measure fair value (such as a pricing model) and/or the risk inherent in the inputs to the valuation technique. Inputs may be observable or unobservable:

a. *Observable inputs* are inputs that reflect the assumptions market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the reporting entity.

b. *Unobservable inputs* are inputs that reflect the reporting entity's own assumptions about the assumptions market participants would use in pricing the asset or liability developed based on the

best information available in the circumstances.

Fair Value Hierarchy

22. To increase consistency and comparability in fair value measurements and related disclosures, the fair value hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three broad levels. The fair value hierarchy gives the highest priority to quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The level in the fair value hierarchy within which the fair value measurement in its entirety falls shall be determined based on the lowest level input that is significant to the fair value measurement in its entirety. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

23. The availability of inputs relevant to the asset or liability and the relative reliability of the inputs might affect the selection of appropriate valuation techniques. However, the fair value hierarchy prioritizes the inputs to valuation techniques, not the valuation techniques. For example, a fair value measurement using a present value technique might fall within Level 2 or Level 3, depending on the inputs that are significant to the measurement in its entirety and the level in the fair value hierarchy within which those inputs fall.

Level 1 Inputs

24. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. A quoted price in an active market provides the most reliable evidence of fair value and shall be used to measure fair value whenever available, except as discussed in paragraphs 25 and 26.

25. If the reporting entity holds a large number of similar assets or liabilities (for example, debt securities) that are required to be measured at fair value, a quoted price in an active market might be available but not readily accessible for each of those assets or liabilities individually. In that case, fair value may be measured using an alternative pricing method that does not rely exclusively on quoted prices (for example, matrix pricing) as a practical expedient. However, the use of an alternative pricing method renders the fair value measurement a lower level measurement.

26. In some situations, a quoted price in an active market might not represent fair value at the measurement date. That might be the case if, for example, significant events (principal-to-principal transactions, brokered trades, or announcements) occur after the close of a market but before the measurement date. The reporting entity should establish and consistently apply a policy for identifying those events that might affect fair value measurements. However, if the quoted price is adjusted for new information, the adjustment renders the fair value measurement a lower level measurement.

27. If the reporting entity holds a position in a single financial instrument (including a block) and the instrument is traded in an active market, the fair value of the position shall be measured within Level 1 as the product of the quoted price for the individual instrument times the quantity held. The quoted price shall not be adjusted because of the size of the position relative to trading volume (blockage factor). The use of a blockage factor is prohibited, even if a market's normal daily trading volume is not sufficient to absorb the quantity held and placing orders to sell the position in a single transaction might affect the quoted price. ¹¹

Level 2 Inputs

28. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs

include the following:

- a. Quoted prices for similar assets or liabilities in active markets
- b. Quoted prices for identical or similar assets or liabilities in markets that are not active, that is, markets in which there are few transactions for the asset or liability, the prices are not current, or price quotations vary substantially either over time or among market makers (for example, some brokered markets), or in which little information is released publicly (for example, a principal-to-principal market)
- c. Inputs other than quoted prices that are observable for the asset or liability (for example, interest rates and yield curves observable at commonly quoted intervals, volatilities, prepayment speeds, loss severities, credit risks, and default rates)
- d. Inputs that are derived principally from or corroborated by observable market data by correlation or other means (market-corroborated inputs).

29. Adjustments to Level 2 inputs will vary depending on factors specific to the asset or liability. Those factors include the condition and/or location of the asset or liability, the extent to which the inputs relate to items that are comparable to the asset or liability, and the volume and level of activity in the markets within which the inputs are observed. An adjustment that is significant to the fair value measurement in its entirety might render the measurement a Level 3 measurement, depending on the level in the fair value hierarchy within which the inputs used to determine the adjustment fall.

Level 3 Inputs

30. Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. However, the fair value measurement objective remains the same, that is, an exit price from the perspective of a market participant that holds the asset or owes the liability. Therefore, unobservable inputs shall reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk). Unobservable inputs shall be developed based on the best information available in the circumstances, which might include the reporting entity's own data. In developing unobservable inputs, the reporting entity need not undertake all possible efforts to obtain information about market participant assumptions. However, the reporting entity shall not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Therefore, the reporting entity's own data used to develop unobservable inputs shall be adjusted if information is reasonably available without undue cost and effort that indicates that market participants would use different assumptions.

Inputs Based on Bid and Ask Prices

31. If an input used to measure fair value is based on bid and ask prices (for example, in a dealer market), the price within the bid-ask spread that is most representative of fair value in the circumstances shall be used to measure fair value, regardless of where in the fair value hierarchy the input falls (Level 1, 2, or 3). This Statement does not preclude the use of mid-market pricing or other pricing conventions as a practical expedient for fair value measurements within a bid-ask spread.

Disclosures

32. For assets and liabilities that are measured at fair value on a recurring basis in periods subsequent to initial recognition (for example, trading securities), the reporting entity shall disclose information that enables users of its financial statements to assess the inputs used to develop those measurements and for recurring fair value measurements using significant unobservable inputs (Level 3), the effect of the measurements on earnings (or changes in net assets) for the period. To meet that objective, the reporting entity shall disclose the following information for each interim and annual period (except as otherwise specified) separately for each major category of assets and liabilities:

- b. The level within the fair value hierarchy in which the fair value measurements in their entirety fall, segregating fair value measurements using quoted prices in active markets for identical assets or liabilities (Level 1), significant other observable inputs (Level 2), and significant unobservable inputs (Level 3)
- c. For fair value measurements using significant unobservable inputs (Level 3), a reconciliation of the beginning and ending balances, separately presenting changes during the period attributable to the following: [12](#)
 - (1) Total gains or losses for the period (realized and unrealized), segregating those gains or losses included in earnings (or changes in net assets), and a description of where those gains or losses included in earnings (or changes in net assets) are reported in the statement of income (or activities)
 - (2) Purchases, sales, issuances, and settlements (net)
 - (3) Transfers in and/or out of Level 3 (for example, transfers due to changes in the observability of significant inputs)
- d. The amount of the total gains or losses for the period in subparagraph (c)(1) above included in earnings (or changes in net assets) that are attributable to the change in unrealized gains or losses relating to those assets and liabilities still held at the reporting date and a description of where those unrealized gains or losses are reported in the statement of income (or activities)
- e. In annual periods only, the valuation technique(s) used to measure fair value and a discussion of changes in valuation techniques, if any, during the period.

33. For assets and liabilities that are measured at fair value on a nonrecurring basis in periods subsequent to initial recognition (for example, impaired assets), the reporting entity shall disclose information that enables users of its financial statements to assess the inputs used to develop those measurements. To meet that objective, the reporting entity shall disclose the following information for each interim and annual period (except as otherwise specified) separately for each major category of assets and liabilities:

- a. The fair value measurements recorded during the period and the reasons for the measurements
- b. The level within the fair value hierarchy in which the fair value measurements in their entirety fall, segregating fair value measurements using quoted prices in active markets for identical assets or liabilities (Level 1), significant other observable inputs (Level 2), and significant unobservable inputs (Level 3)
- c. For fair value measurements using significant unobservable inputs (Level 3), a description of the inputs and the information used to develop the inputs
- d. In annual periods only, the valuation technique(s) used to measure fair value and a discussion of changes, if any, in the valuation technique(s) used to measure similar assets and/or liabilities in prior periods.

34. The quantitative disclosures required by this Statement shall be presented using a tabular format. (See Appendix A.)

35. The reporting entity is encouraged, but not required, to combine the fair value information disclosed under this Statement with the fair value information disclosed under other accounting pronouncements (for example, FASB Statement No. 107, Disclosures about Fair Value of Financial Instruments) in the periods in which those disclosures are required, if practicable. The reporting entity also is encouraged, but not required, to disclose information about other similar measurements (for example, inventories measured at market value under ARB 43, Chapter 4), if practicable.

Effective Date and Transition

36. Except as provided in subparagraphs 36(a) and 36(b) below, this Statement shall be effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any financial statements for an interim period within that fiscal year.

- a. Delayed application of this Statement is permitted for nonfinancial assets and nonfinancial

liabilities liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008, and interim periods within those fiscal years

b. An entity that has issued interim or annual financial statements reflecting the application of the measurement and disclosure provisions of this Statement prior to the issuance of FSP FAS 157-2, Effective Date of FASB Statement No. 157, must continue to apply all of the provisions of this Statement.

37. This Statement shall be applied prospectively as of the beginning of the fiscal year in which this Statement is initially applied, except as follows. This Statement shall be applied retrospectively to the following financial instruments as of the beginning of the fiscal year in which this Statement is initially applied (a limited form of retrospective application):

a. A position in a financial instrument that trades in an active market held by a broker-dealer or investment company within the scope of the AICPA Audit and Accounting Guides for those industries that was measured at fair value using a blockage factor prior to initial application of this Statement

b. A financial instrument that was measured at fair value at initial recognition under Statement 133 using the transaction price in accordance with the guidance in footnote 3 of EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," prior to initial application of this Statement

c. A hybrid financial instrument that was measured at fair value at initial recognition under Statement 133 using the transaction price in accordance with the guidance in Statement 133 (added by FASB Statement No. 155, Accounting for Certain Hybrid Financial Instruments) prior to initial application of this Statement.

38. At the date this Statement is initially applied to the financial instruments in paragraph 37(a)-(c), a difference between the carrying amounts and the fair values of those instruments shall be recognized as a cumulative-effect adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year, presented separately. The disclosure requirements of Statement 154 for a change in accounting principle do not apply.

39. The disclosure requirements of this Statement (paragraphs 32-35), including those disclosures that are required in annual periods only, shall be applied in the first interim period of the fiscal year in which this Statement is initially applied. The disclosure requirements of this Statement need not be applied for financial statements for periods presented prior to initial application of this Statement.

The provisions of this Statement need

not be applied to immaterial items.

This Statement was adopted by the unanimous vote of the seven members of the Financial Accounting Standards Board:

Robert H. Herz, *Chairman*
George J. Batavick
G. Michael Crooch
Thomas J. Linsmeier
Leslie F. Seidman
Edward W. Trott
Donald M. Young



Federal Accounting Standards Advisory Board

**Accounting for
Federal Oil and Gas Resources**

Statement of Federal Financial Accounting Standards

Revised Exposure Draft

Written comments are requested by [date 60 days after issuance]

[Month day, year]

Working Draft – Comments from Respondents Are Not Requested on This Draft

THE FEDERAL ACCOUNTING STANDARDS ADVISORY BOARD

The Secretary of the Treasury, the Director of the Office of Management and Budget (OMB), and the Comptroller General, established the Federal Accounting Standards Advisory Board (FASAB or "the Board") in October 1990. FASAB 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 standards are 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 or its website:

- "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", Exposure drafts, Statements of Federal Financial Accounting Standards and Concepts, FASAB newsletters, and other items of interest are posted on FASAB's website at: www.fasab.gov.

Federal Accounting Standards Advisory Board

441 G Street, NW, Suite 6814

Mail stop 6K17V

Washington, DC 20548

Telephone 202-512-7350

FAX – 202-512-7366

www.fasab.gov

This is a work of the U. S. government and is not subject to copyright protection in the United States. It may be reproduced and distributed in its entirety without further permission from FASAB. However, because this work may contain copyrighted images or other material, permission from the copyright holder may be necessary if you wish to reproduce this material separately.



1 **ISSUE DATE**

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

3 The Federal Accounting Standards Advisory Board (FASAB or the Board) is requesting
4 comments on the revised exposure draft of a proposed Statement of Federal Financial
5 Accounting Standards entitled, *Accounting for Federal Oil and Gas Resources*.

6 Substantive changes have been made to the original exposure draft issued on May 21,
7 2007.

8 Specific questions for your consideration [begin](#) on page 1 but you are welcome to
9 comment on any aspect of this proposal. If you do not agree with the proposed
10 approach, your response would be more helpful to the Board if you explain the reasons
11 for your position and any alternative you propose. Responses are requested by **DUE**
12 **DATE**.

Deleted: appear

13 All comments received by the FASAB are considered public information. Those
14 comments may be posted to the FASAB's website and will be included in the project's
15 public record.

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

21 Wendy M. Payne, Executive Director
22 Federal Accounting Standards Advisory Board
23 Mailstop 6K17V
24 441 G Street, NW, Suite 6814
25 Washington, DC 20548

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

30

31 Tom L. Allen
32 Chairman

[This page intentionally left blank.]

1 Executive Summary

2 What is the Board proposing?

3 This exposure draft (ED) proposes accounting standards for federal oil and gas
4 resources.¹ The proposed standards would result in the recognition of an asset and a
5 liability. The asset would be referred to as "estimated petroleum royalties." The asset's
6 value would be the royalty share of the federal oil and gas resources classified as
7 "proved reserves."² The liability would be for the royalty share of the federal proved
8 reserves designated to be distributed to non-federal entities, e.g., state governments,³

9 When oil and gas resources are extracted, revenue and a depletion expense equal to
10 the revenue due would be recognized by the federal government. When revenue
11 collections are distributed, a transfer out for revenue distributions to federal entities and
12 a reduction in the liability for revenue distributions to non-federal entities would be
13 recognized. Gains and losses would be recognized based on an annual valuation of the
14 asset with an adjustment to the liability for revenue distributions to non-federal entities.
15 In addition, when rights to a future royalty stream are identified to be sold, the value of
16 the related rights would be disclosed.

17 Transition to these proposed standards would require that the federal government's
18 royalty share of oil and gas proved reserves be recognized as an asset as of the
19 beginning of the reporting period in which the standards become effective. In addition,
20 a liability for the portion that will be distributed to non-federal entities would be
21 established at the same time. The net effect of recognizing an asset and establishing a
22 liability for revenue distributions to non-federal entities at the beginning of the reporting
23 period would be a change in accounting principle that increases the entity's net position.

24 The proposed standards would be effective as RSI for periods beginning after September
25 30, 2010, and as basic information for periods beginning after September 30, 2013,
26 except where specifically designated as required supplementary information (RSI).
27 Earlier implementation is encouraged.

Deleted: others

Deleted: i.e

Deleted: and – at the component
entity level – other federal agencies
and the general fund of the U.S.
Treasury

Deleted: and royalties are

Deleted: earned

Comment: Removed incorrect use
of the term "earned" as pointed out by
W. Jackson.

Deleted: earned

Deleted: others

Deleted: others

Deleted: others

Deleted: 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).

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 non-federal party.

² A portion of the production value of proved oil and gas reserves are due to the federal government from
the lessee in accordance with the royalty rate contained in the lease agreement.

³ Upon collection, the majority of the federal government's estimated petroleum royalties from the
production of federal oil and gas proved reserves are distributed to state governments, other federal
agencies, and the general fund of the U.S. Treasury in accordance with legislated allocation formulas.

Deleted: states

1 **How would this proposal improve federal financial reporting and contribute to**
2 **meeting the federal financial reporting objectives?**

3 The federal government is accountable to the American citizens for proper stewardship
4 of federal assets. Federal oil and gas resources represent federal assets. Accounting
5 for and reporting information about these assets would enhance:

- 6 a. accountability for and stewardship over assets of the federal government;
- 7 b. consistency and understandability in accounting for assets of the federal
- 8 government; and,
- 9 c. relevance, consistency, and comparability of information regarding revenue of
- 10 the federal government.

11
12 Recognizing the federal government's royalty share of proved reserves as an asset on
13 the balance sheet would provide transparency regarding the value and changes in value
14 of these significant assets. Federal financial reports would be more relevant, consistent,
15 and complete. In addition, recognizing oil and gas resources on the government's
16 balance sheet would enable the federal government to clearly communicate the effect of
17 some of the legislative changes related to oil and gas resources to the taxpayers in the
18 period that the changes are made (e.g., opening additional lands for leasing or
19 increasing the percentage of royalties to be distributed to the states). Additional
20 disclosures about federal oil and gas resources would provide comprehensive
21 information about federal assets,
22 reveal changes in the quantity and
23 status of oil and gas resources, and
24 make quantity information more
25 accessible to users of financial
26 information.

27 Bonus bid, rent, and royalty
28 collections – currently treated as
29 nonexchange revenue due to the
30 absence of cost information – would
31 be accounted for and reported in
32 accordance with exchange revenue
33 standards. This treatment would
34 improve the comparability of revenue
35 information.

36 Of the four objectives outlined in
37 Statement of Federal Financial
38 Accounting Concepts Statement
39 (SFFAC) 1, *Objectives of Federal*
40 *Financial Reporting*, the operating

Operating Performance Objective
<p>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</p> <ul style="list-style-type: none"> – 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. <p style="text-align: right;">Source: SFFAC 1</p>

Deleted: The effect of some

Inserted: The effect of some legislative changes related to oil and gas resources would be communicated to the taxpayers in the period that the changes are made

Deleted: would be communicated

Comment: From A. Schumacher: Not sure where this would be disclosed and what it is trying to accomplish. Staff attempted to clarify.

1 performance and stewardship objectives were identified as most important for natural
 2 resources reporting.
 3

4 With respect to meeting the operating performance reporting objective, the proposed
 5 standards would provide information useful in evaluating the reporting entity's
 6 management of assets relating to oil and gas resources. This information would allow
 7 financial report users to monitor changes in royalty rates and estimated reserve
 8 quantities, providing an indicator of how well the government's proved reserves were
 9 managed. In addition, the value of the estimated petroleum royalties at the end of each
 10 period would facilitate consideration of the potential cash flows from existing leases.
 11

12 Currently, royalties from oil and gas leases are displayed on the statement of changes
 13 in net position with non-exchange revenue rather than on the statement of net cost with
 14 other exchange revenue. Presentation of revenues arising from oil and gas leasing
 15 activities as exchange revenue would assist users in understanding how the
 16 government's efforts and
 17 accomplishments were financed. The
 18 current practice of combining
 19 revenues derived from the sale of
 20 assets with revenues derived from
 21 taxation or other non-exchange
 22 sources may obscure the fact that
 23 ~~costs were incurred to generate the~~
 24 ~~revenues—the federal government~~
 25 ~~exchanged~~ proved reserves for a
 26 future stream of royalty payments.

Stewardship Objective	
<p>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</p> <ul style="list-style-type: none"> – 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. <p style="text-align: right;">Source: SFFAC 1</p>	<p>Deleted: the gains were obtained through the exchange of resources</p> <p>Comment: From H. Steinberg: What the reader gets from the changes proposed by this standard is an understanding of the costs incurred to generate the revenue. A better argument might be that the current practice obscures the fact that costs were incurred to generate the revenues.</p>

27 With respect to meeting the
 28 stewardship reporting objective, the
 29 proposed standards would provide
 30 information useful in assessing
 31 whether federal government
 32 operations have contributed to the
 33 nation's current and future well-being.

34 Recognition of estimated petroleum royalties as an asset would make available the
 35 value of an asset that generates cash to finance government operations over time. This
 36 would inform users about the financial position of the government and whether it was
 37 improving or deteriorating over time. Information about potential oil and gas production
 38 and changes in potential production over time would allow users to consider how
 39 government operations and economic conditions have impacted the availability of oil
 40 and gas resources to future generations.

[This page intentionally left blank.]

Table of Contents

Executive Summary	i
What is the Board proposing?	i
How would this proposal improve federal financial reporting and contribute to meeting the federal financial reporting objectives?.....	ii
Questions for Respondents	1
Introduction	3
Purpose	3
Materiality	3
Estimation Methodology	4
Effective Date	4
Proposed Standards.....	5
Scope	5
Definitions.....	5
Asset Recognition.....	6
Liability Recognition.....	8
Revenue and Expense Recognition.....	9
Future Royalty Rights Identified for Sale	10
Annual Valuation of Estimated Petroleum Royalties.....	11
Disclosures and Required Supplementary Information.....	12
Component Entity Disclosures	12
Component Entity Required Supplementary Information (RSI).....	14
Federal Receiving Entity Accounting and Reporting.....	14
Consolidated Financial Report (CFR) of the United States Government Disclosures	15

Disclosure Requirements for Fiduciary Oil and Gas Resources	15
Effect on Existing Standards.....	16
Effective Date	17
Appendix A: Basis for Conclusions	18
Project History	18
Overview of Federal Oil and Gas Resources.....	19
Conceptual Aspects of Federal Oil and Gas Resources as an Asset for Estimated Petroleum Royalties and a Liability for the Portion of Revenue to be Distributed to Non-Federal Entities	23
Recognition Criteria.....	23
Asset Recognition	24
Liability Recognition	29
Reporting the Gains and Losses from Changes in Assumptions and Selecting Discount Rates	31
Future Rights to Royalty Streams Identified for Sale	32
Disclosures	33
Original Exposure Draft	33
Significant Changes Made to the Original Exposure Draft.....	38
Appendix B: Illustration of the Components of Federal Oil and Gas Resources	41
Appendix C: Pro Forma Transactions and Financial Statements	43
Appendix D: Abbreviations	55
Appendix E: Glossary.....	57

1 **Questions for Respondents**

2 The FASAB encourages you to become familiar with all proposals in the Statement
 3 before responding to the questions in this section. In addition to the questions below,
 4 the Board also would welcome your comments on other aspects of the proposed
 5 Statement.

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

Deleted: Federal
 Deleted: Federal

11 Because the proposals may be modified before a final Statement is issued, it is
 12 important that you comment on proposals that you favor as well as any that you do not
 13 favor. Comments that include the reasons for your views will be especially appreciated.

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

18 Wendy M. Payne, Executive Director
 19 Federal Accounting Standards Advisory Board
 20 Mailstop 6K17V
 21 441 G Street, NW, Suite 6814
 22 Washington, DC 20548

23 All responses are requested by **[insert date]**.

24 Q1. The original exposure draft (ED) issued on May 21, 2007, contained detailed
 25 asset valuation implementation guidance for valuing oil and gas resources. As
 26 a result of feedback received from field testing efforts, the Board has removed
 27 that detailed guidance from this revised ED and is instead proposing to provide
 28 federal entities with flexibility in developing the asset valuation estimation
 29 methodology due to the constantly changing economic and technical
 30 conditions. Do you agree or disagree with the Board's position (see
 31 paragraphs 19 through 23 and A42)? Please explain the reasons for your
 32 position in as much detail as possible.

Deleted: Based on
 Deleted: T
 Comment: Based on comment from Hal Steinberg.
 Deleted: for valuing oil and gas resources
 Deleted: The detailed asset valuation implementation guidance contained in the original exposure draft (ED) issued on May 21, 2007, has been removed from this revised ED.

33 Q2. The Board believes that the method for valuing the federal government's
 34 estimated petroleum royalties should approximate the present value of future
 35 federal royalty receipts on proved reserves known to exist as of the reporting
 36 date. Do you agree or disagree with the Board's position (see paragraphs 20

- 1 and A36 through A41)? Please explain the reasons for your position in as
2 much detail as possible.
- 3 Q3. The Board is proposing to permit alternative measurement methods for valuing
4 the federal government's estimated petroleum royalties if it is not reasonably
5 possible to estimate the present value of future federal royalty receipts on
6 proved reserves. Do you agree or disagree with the Board's position (see
7 paragraph 24)? Please explain the reasons for your position in as much detail
8 as possible.
- 9 Q4. The Board is proposing to permit federal entities to change its methodology for
10 valuing the federal government's estimated petroleum royalties if
11 environmental or other changes would provide for the development of an
12 improved methodology. Do you agree or disagree with the Board's position
13 (see paragraphs 25, 26 and A44 through A47)? Please explain the reasons for
14 your position in as much detail as possible.
- 15 Q5. The Board believes that it would be appropriate to apply the guidance
16 regarding reporting gains and losses from changes in assumptions and
17 selecting the discount rates from SFFAS 33, *Pensions, Other Retirement*
18 *Benefits, and Other Postemployment Benefits: Reporting the Gains and Losses*
19 *from Changes in Assumptions and Selecting Discount Rates and Valuation*
20 *Dates*, to long-term assumptions about oil and gas when using the present
21 value method. Do you agree or disagree with the Board's position (see
22 paragraphs 21, 40, and A60 through A62)? Please explain the reasons for your
23 position in as much detail as possible.
- 24 Q6. The Board is proposing to provide a three-year phase-in of the proposed
25 requirements from required supplementary information (RSI) beginning with
26 fiscal year 2011 to basic in fiscal year 2014. This transitional period is being
27 provided to allow for the asset valuation methodology to be improved upon
28 before an audit opinion is required. Do you agree or disagree with the Board's
29 position (see paragraphs 51 and A83)? Please explain the reasons for your
30 position in as much detail as possible.

1 Introduction**2 Purpose**

- 3 1. Statements of Federal Financial Accounting Standards (SFFAS) 6,
4 *Accounting for Property, Plant, and Equipment*; 8, *Supplementary*
5 *Stewardship Reporting*; and 29, *Heritage Assets and Stewardship Land*,
6 establish standards related to federal lands, but specifically exclude natural
7 resources from the scope of those standards. Extensive federal oil and gas
8 resources exist on public lands throughout the country and on the Outer
9 Continental Shelf (OCS). Currently, federal financial reporting does not
10 provide information about the quantity or value of these assets. In addition,
11 royalty revenues are recognized but expenses are not recognized for the
12 asset exchanged to produce those revenues.
- 13 2. The Board believes that federal oil and gas resources represent federal
14 assets and accounting for and reporting information about these assets
15 would enhance:
 - 16 a. accountability for and stewardship over assets of the federal
17 government;
 - 18 b. consistency and understandability in accounting for assets of the
19 federal government; and,
 - 20 c. relevance, consistency, and comparability of information regarding
21 revenue of the federal government.
- 22 3. This Statement provides for a more complete accounting for oil and gas
23 resources available to the federal government. Recognizing the federal
24 government's royalty share of proved reserves as an asset on the balance
25 sheet would provide transparency regarding the value and changes in value
26 of these significant assets and result in information that contributes to
27 meeting federal financial reporting objectives.

Deleted: s

28 Materiality

- 29 4. The provisions of this Statement need not be applied to immaterial items.
30 The determination of whether an item is material depends on the degree to
31 which omitting or misstating information about the item makes it probable
32 that the judgment of a reasonable person relying on the information would
33 have been changed or influenced by the omission or the misstatement.

1 **Estimation Methodology**

- 2 5. The Board believes that the detailed estimation methodology for valuing oil
3 and gas natural resources should be developed by federal entities rather
4 than centrally by the Board. In an environment heavily affected by changes
5 in prices, technological advancements, economic and operating conditions,
6 and known geological, engineering, and economic data, estimation
7 methodologies may need to be regularly updated to reflect changing
8 economic and technological conditions.

9 **Effective Date**

- 10 6. The proposed standards are effective as RSI for periods beginning after
11 September 30, 2010, and as basic information for periods beginning after
12 September 30, 2013, except where specifically designated as RSI. Earlier
13 implementation is encouraged.

1 | Proposed Standard~~s~~2 | **Scope**

- 3 | 7. This Statement applies to federal entities that report information about
 4 | federal oil and gas resources in general purpose financial reports, including
 5 | the consolidated financial report of the U.S. Government (CFR), prepared
 6 | in conformance with Federal Accounting Standards Advisory Board
 7 | (FASAB) standards.
- 8 | 8. This Statement articulates a general principle that should guide preparers of
 9 | general purpose federal financial reports in accounting for federal oil and
 10 | gas resources.
- 11 | 9. The concepts of an asset and a liability contained in this document are
 12 | consistent with those established in Statement of Federal Financial
 13 | Accounting Concepts (SFFAC) 5, *Definitions of Elements and Basic*
 14 | *Recognition Criteria for Accrual-Basis Financial Statements*. This
 15 | Statement establishes accounting for assets and liabilities related to federal
 16 | oil and gas resources that are not addressed by prior standards.
- 17 | 10. This Statement also amends SFFAS 7, *Accounting for Revenue and Other*
 18 | *Financing Sources*, to account for and report bonus bid, rent, and royalty
 19 | collections – currently treated as nonexchange revenue due to the absence
 20 | of cost information – in accordance with exchange revenue standards.

Comment: From H. Steinberg

Deleted: exclusively

Comment: From H. Steinberg – Is it fully understood that federal entities include the CFR? Does this have to be made explicit.

21 | **Definitions**

- 22 | 11. Definitions in paragraphs 12 and 13 are presented first in the proposed
 23 | accounting standards because of their uniqueness in calculating the asset
 24 | value of estimated petroleum royalties. Other terms shown in **boldface**
 25 | **type** the first time they appear in this document are presented in the
 26 | Glossary (see page 57). Reviewers of this document may want to examine
 27 | all definitions before reviewing the proposed accounting standards and
 28 | Basis for Conclusions.
- 29 | 12. **Federal Oil and Gas Resources:** Oil and gas resources over which the
 30 | federal government may exercise sovereign rights with respect to
 31 | exploration and exploitation and from which the federal government has the
 32 | authority to derive revenues for its use. Federal oil and gas resources do
 33 | not include resources over which the federal government acts as a fiduciary
 34 | for the benefit of a non-federal party.

Deleted: through

1 | **13. Regional Estimated Petroleum Royalties:** Regional estimated petroleum
 2 | royalties means the estimated end-of-period value of the federal
 3 | government’s royalty share of proved oil and gas reserves from federal oil
 4 | and gas resources in each region.

5 | **Asset Recognition**

6 | **14.** Extensive federal oil and gas resources exist on public lands throughout the
 7 | country and on the **Outer Continental Shelf** (OCS). These resources will
 8 | provide economic benefits to the federal government through revenue from
 9 | leasing activities and the collection of royalties on production. The federal
 10 | government controls access to these resources.

11 | **15.** Federal oil and gas resources are made up of **two primary components –**
 12 | **reserves and undiscovered resources. Reserves can be further defined as**
 13 | **either proved or unproved while undiscovered resources can be further**
 14 | **defined as either recoverable or non-recoverable.** See Appendix B:
 15 | Illustration of the Components of Federal Oil and Gas Resources on page
 16 | 41 for an illustration of the universe of federal oil and gas resources and a
 17 | further breakdown of its components.

18 | **16.** Information is available in varying degrees and with varying reliability for
 19 | each component. While all of the federal oil and gas resources meet the
 20 | definition of **an** asset, the Board does not believe that the information for
 21 | other than proved reserves is sufficiently reliable to be recognized.

22 | **17.** The federal government’s estimated petroleum royalties from the production
 23 | of federal oil and gas proved reserves **should** be recognized as an asset on
 24 | the balance sheet of the component entity that is responsible for collecting
 25 | royalties. The value of the federal government’s estimated petroleum
 26 | royalties **should** be computed based on the calculation of federal oil and gas
 27 | proved reserves on a regional basis.

28 | **18.** For purposes of **these standards**, the regions used in determining and
 29 | reporting regional amounts or factors **should** be collaboratively developed
 30 | by all the component entities involved in oil and gas resource activities.
 31 | Regions used in calculating Regional Estimated Petroleum Royalties and in
 32 | applying **these standards** **should** be consistent and aligned with regions
 33 | used internally by the component entities in administering federal oil and
 34 | gas resource activities.

Deleted: <#>Regional Average First Purchase Price for Oil: The regional average first purchase price for oil is calculated by dividing the total regional sales value of oil 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 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. ¶

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

<#>Effective Regional Average Royalty Rate: The effective regional average royalty rate is calculated by dividing the royalty value (royal ... [1]

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: discovered resources

Deleted: Discovered and undiscovered resources

Deleted: three different components -

Deleted: reserves

Deleted: , technically recoverable resources,

Deleted: and

Deleted: or

Inserted: or

Deleted: undiscovered

Deleted: nonrecoverable resources

Inserted: nonrecoverable

Deleted: shall

Deleted: shall

Deleted: this

Deleted: shall

Deleted: this

Deleted: shall

1 | 19. The Board believes that the detailed estimation methodology for valuing oil
 2 | and gas natural resources should be developed by federal entities rather
 3 | than centrally by the Board.⁴ In an environment heavily affected by changes
 4 | in prices, technological advancements, economic and operating conditions,
 5 | and known geological, engineering, and economic data, estimation
 6 | methodologies may need to be regularly updated to reflect changing
 7 | economic and technological conditions.

8 | 20. The estimates that are developed should approximate the **present value** of
 9 | future federal royalty receipts on proved reserves known to exist as of the
 10 | reporting date. The estimates should be based on the best information
 11 | available at fiscal year-end, or as close to the fiscal year-end as possible.

12 | 21. Discount rates as of the reporting date for present value measurements of
 13 | oil and gas assets and liabilities should be based on interest rates on
 14 | **marketable Treasury securities** with maturities consistent with the cash
 15 | flows being discounted as required for pension, other retirement benefits
 16 | (ORB) and other postemployment benefits (OPEB) in SFFAS 33, *Pensions,*
 17 | *Other Retirement Benefits, and Other Postemployment Benefits: Reporting*
 18 | *the Gains and Losses from Changes in Assumptions and Selecting*
 19 | *Discount Rates and Valuation Dates.*⁵

20 | 22. The entity's estimates should reflect its judgment about the outcome of
 21 | events based on past experience and expectations about the future.
 22 | Estimates should reflect what is reasonable to assume under the
 23 | circumstances. While the entity's own assumptions about future cash flows
 24 | may be used, the entity should review assumptions used generally in the
 25 | federal government as evidenced by sources independent of the reporting
 26 | entity, for example, those used by the Bureau of Economic Analysis for the
 27 | National Income and Product Accounts. If the entity's own assumptions do
 28 | not reflect data that is consistent with sources independent of the reporting
 29 | entity, an explanation of why it is inappropriate to do so should be disclosed.

Deleted: The

Deleted: . However

Deleted: and, i

Deleted: its

Deleted: such

Comment: From H. Steinberg – The syntax is confusing. Do you mean "consistent with the data used in the Bureau's assumptions?" That would be clearer, but maybe sound too prescriptive. Staff note: This paragraph was copied straight from SFFAS 33, par. 35; however, staff attempted to edit it to clarify language.

30 | 23. The estimates of future federal royalty receipts on proved reserves known to
 31 | exist as of the reporting date should be divided further by commodity and
 32 | type (e.g., wet gas, **dry gas**, oil and **lease condensate**, onshore, offshore,
 33 | etc.) and calculated separately if material differences would otherwise
 34 | result. Each of the individual calculations should be summed together to
 35 | arrive at the federal government's total estimated petroleum royalties.

⁴ Estimates that do not lead to material misstatements are acceptable without guidance from the Board.

⁵ See SFFAS 33, paragraphs 28 through 32.

Deleted: for additional guidance

- 1 24. The preferred measurement method for valuing the federal government's
 2 estimated petroleum royalties is the present value of future federal royalty
 3 receipts on proved reserves as provided in paragraphs 20 through 23;
 4 however, methods for measuring fair value may be acceptable if it is not
 5 reasonably possible to estimate present value.⁶
- 6 25. Once established, the estimation methodology should be consistently
 7 followed and disclosed in the financial reports. If environmental or other
 8 changes would provide for the development of an improved methodology,
 9 the nature and reason for the change in methodology, as well as the effect
 10 of the change, should be disclosed. The net effect of a change in
 11 methodology after the initial year should be accounted for as a change in
 12 accounting estimate effected by a change in accounting principle.⁷
- 13 26. A change in accounting estimate should be accounted for in (a) the period
 14 of change if the change affects that period only or (b) the period of change
 15 and future periods if the change affects both. A change in accounting
 16 estimate should not be accounted for by restating or retrospectively
 17 adjusting amounts reported in financial statements of prior periods or by
 18 reporting pro forma amounts for prior periods.⁸

Deleted: another

Deleted: ology

Inserted: ology

Deleted: I

Deleted: the

Deleted: of future federal royalty receipts on proved reserves, then the value of the federal government's estimated petroleum royalties may be computed by multiplying the estimated quantity of proved oil and gas reserves under federal lands by the average first purchase price for oil or average wellhead price for gas and the effective average royalty rate by region. Other methodologies may be acceptable.

Comment: From J. Farrell: Document should be clear whether this is a change in estimate or change in principle. Staff: Incorporated FAS 154 guidance into standard.

Liability Recognition

- 19
- 20 27. Upon collection, the majority of the federal government's estimated
 21 petroleum royalties from the production of federal oil and gas proved
 22 reserves are distributed to state governments, other federal agencies, and
 23 the general fund of the U.S. Treasury in accordance with legislated
 24 allocation formulas. The legislated allocation formulas constitute a present
 25 obligation⁹ of the component entity that is responsible for collecting royalties
 26 to provide assets to another entity, and the underlying legislation identifies
 27 the conditions under which these distributions will be made.

Formatted: Bullets and Numbering

⁶ FAS 157, Fair Value Measurements, provides a framework for measuring fair value.

⁷ A change in accounting estimate effected by a change in accounting principle is a change in accounting estimate that is inseparable from the effect of a related change in accounting principle. An example of a change in estimate effected by a change in principle is a change in the method of depreciation, amortization, or depletion for long-lived, nonfinancial assets.

⁸ Statement of Financial Accounting Standards (SFAS) 154, Accounting Changes and Error Corrections (as amended), pars. 2e, and 19 – 21.

⁹ The term obligation is used in this Statement 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.

Formatted: Space After: 0 pt

1 28. A long-term liability and corresponding expense for estimated petroleum
 2 royalty revenue distributions to non-federal entities (e.g., state governments)
 3 should be recognized by the component entity that is responsible for
 4 collecting royalties in conjunction with the recognition of an asset for
 5 estimated petroleum royalties. The amount of the liability should be
 6 estimated based on the portion of the royalty share of the federal proved oil
 7 and gas reserves designated to be distributed to non-federal
 8 entities over the preceding twelve (12) months may be an acceptable basis
 9 for estimating petroleum royalties to be distributed. Other methodologies
 10 may be acceptable. The corresponding expense should be recognized in a
 11 manner consistent with existing standards.

13 29. The estimated portion of the liability for royalty revenue distributions to non-
 14 federal entities expected to be distributed within 12 months of the fiscal
 15 year-end may be classified as current.

16 30. The cumulative net effect of recognizing an asset and establishing a liability
 17 for revenue distributions to non-federal entities at the beginning of the
 18 reporting period for which these standards are fully effective should be
 19 reported as a "change in accounting principle" that increases the entity's net
 20 position. The adjustment should be made to the beginning balance of
 21 cumulative results of operations on the statement of changes in net position
 22 for the period that the change is made in accordance with SFFAS 21,
 23 Reporting Corrections of Errors and Changes in Accounting Principles. In
 24 the initial year of implementation, prior year information should not be
 25 restated.

Revenue and Expense Recognition

27 31. Bonus bid and rent revenue relating to federal oil and gas resources
 28 should be recognized as exchange revenue on the statement of net cost of
 29 the component entity that is responsible for collecting royalty revenue.¹⁰ In
 30 addition, a liability¹¹ and corresponding expense for bonus bid and rent
 31 revenue distributions to non-federal entities should be recognized by the
 32 component entity that is responsible for collecting royalties in conjunction
 33 with the recognition of the bonus bid and rent revenue. The amount of the

Comment: Staff note: For further discussion, refer to Issue Paper No. 3 at Appendix 1 of the Feb issue paper.

Formatted: Bullets and Numbering

Comment: Staff note: For further discussion, refer to Issue Paper No. 6 at Appendix 1 of the Feb issue paper.

Deleted: others

Deleted: states

Deleted: shall

Deleted: on the balance sheet of

Deleted: shall

Deleted: present value

Deleted: others, e.g., the states, the general fund of the U.S. Treasury and other federal agencies

Deleted: others

Deleted: to others

Comment: Staff note: For further discussion, refer to Issue Paper No. 3 at Appendix 1 of the Feb issue paper.

Deleted: shall

Inserted: shall

Deleted: would be

Deleted: shall

Deleted: shall

Formatted: Bullets and Numbering

Deleted: shall

Deleted: and/or transfer out

Deleted: others

Deleted: shall

¹⁰ Per SFFAS 7, *Accounting for Revenue and Other Financing Sources*, paragraph 34.

¹¹ 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 non-federal entities may be classified as an other current liability consistent with SFFAS 1 if the definition is met.

1 liability should be the bonus bid and rent revenues designated to be
 2 distributed to non-federal entities, e.g., state governments. The
 3 corresponding expense should be recognized in a manner consistent with
 4 existing standards.

- Deleted: shall
- Deleted: others
- Deleted: the states
- Deleted: , the general fund of the U.S. Treasury and other federal agencies
- Deleted: and/or transfer out
- Deleted: shall
- Deleted: shall
- Deleted: shall
- Deleted: shall

5 **32. Royalties** from the production of federal oil and gas proved reserves should
 6 be recognized as exchange revenue on the statement of net cost by the
 7 component entity that is responsible for collecting the royalty revenue. At
 8 the same time, an amount equal to the royalty revenue should be
 9 recognized as depletion expense on the statement of net cost of the
 10 component entity that is responsible for collecting the royalty revenue and
 11 the value of estimated petroleum royalties should be reduced by the
 12 depletion expense amount.¹²

13 **Future Royalty Rights Identified for Sale**

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

- Formatted: Bullets and Numbering
- Deleted: shall
- Deleted: shall
- Deleted: shall

19 **34.** The calculated value disclosed for future royalty rights identified for sale
 20 should be based on the specific **field** to be sold.

- Deleted: shall

21 **35.** When the future royalty rights identified for sale are sold, the calculated
 22 value of the future royalty rights sold should be removed from the estimated
 23 petroleum royalties account at the time of the sale. Any difference between
 24 this calculated value and the actual sales proceeds results in a net gain or
 25 loss.

- Deleted: shall

26 **36.** The net gain or loss should be reported on the statement of net cost of the
 27 component entity that is responsible for collecting royalties. In addition, if
 28 the sale produced a net gain, the liability and a corresponding expense for
 29 the revenue distributions to non-federal entities should be increased by an
 30 amount equal to the amount of the gain designated to be distributed to non-
 31 federal entities, e.g., state governments. If the sale produced a net loss, the
 32 liability and a corresponding expense for the revenue distributions to non-
 33 federal entities should be decreased by an amount equal to the amount of
 34 the loss, which will reduce future distributions to others.

- Deleted: shall
- Deleted: and/or transfer-out
- Deleted: others
- Deleted: shall
- Deleted: others
- Deleted: the states
- Deleted: , the general fund of the U.S. Treasury and other federal agencies
- Deleted: and/or transfer-out
- Deleted: others
- Deleted: shall

¹² 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.

Annual Valuation of Estimated Petroleum Royalties

37. The estimated petroleum royalties asset should be valued at the end of each fiscal year for financial statement reporting.

Formatted: Bullets and Numbering

Deleted: shall

38. The calculated value of estimated petroleum royalties at year-end should 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, the book value should be increased to the new estimate and a gain should be recognized 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 should be decreased to the new estimate and a loss should be recognized on the statement of net cost.

Comment: From DOI Field Test Team.

Deleted: shall

Deleted: shall

Deleted: shall

Deleted: recorded

Deleted: shall

Deleted: shall

Deleted: recorded

39. 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 non-federal entities should be increased or decreased to the amount expected to be distributed. If the revaluation resulted in a net gain, the liability and a corresponding expense for the revenue distributions to non-federal entities should be increased by an amount equal to the amount of the gain designated to be distributed to non-federal entities, e.g., state governments. If the revaluation resulted in a net loss, the liability and a corresponding expense for the revenue distributions to non-federal entities should be decreased by an amount equal to the amount of the loss, which will reduce future distributions to others.

Deleted: others

Deleted: shall

Deleted: and/or transfer-out

Deleted: others

Deleted: shall

Deleted: others

Deleted: the states

Deleted: , the general fund of the U.S. Treasury and other federal agencies

Deleted: and/or transfer-out

Deleted: others

Deleted: shall

40. For estimates that are developed using present value, component entities should display gains and losses from changes in long-term assumptions used to measure assets and liabilities for oil and gas as a separate line item or line items on the statement of net costs as required for pensions, ORB, and OPEB in SFFAS 33.

Comment: From H. Steinberg: This is very important. I do not know whether the standard is referring to just changes in the interest rates, or it is referring to changes in the estimates of the quantities, costs of production, sales price, and/or timing of the sales.

Deleted: (Staff will explore the need for additional guidance on what would constitute a change in assumption for oil and gas vs. true gains and losses.)

13 The estimated petroleum royalties beginning balance would have been reduced by the amount of depletion expense recognized during the year.

Deleted: d on the statement of net cost

14 For example, the average annual share of the revenue distributed to others over the preceding twelve (12) months may be an acceptable basis to estimate future distributions. Other methodologies may be acceptable.

15 See SFFAS 33, paragraphs 19 through 27.

Deleted: for additional guidance

1 **Disclosures and Required Supplementary Information**

2 | **41.** Notes to the financial statements are an integral part of the basic financial
3 | statements, essential for complete and fair presentation in conformity with
4 | generally accepted accounting principles for the federal government.

Formatted: Bullets and Numbering

5 Component Entity Disclosures

6 | **42.** The component entity responsible for reporting the federal government's
7 | estimated petroleum royalties on its balance sheet **should** provide the
8 | following as note disclosures:

Formatted: Bullets and Numbering

Deleted: shall

9 a. A concise statement explaining how the management of federal
10 | oil and gas resources is important to the overall mission of the
11 | entity.

12 b. A brief description of the entity's stewardship policies for federal
13 | oil and gas resources. The stewardship policies for federal oil
14 | and gas resources **should** describe the guiding principles
15 | established to: assess the oil and gas resource areas; offer those
16 | resources to interested developers; sell and assign **leases** to
17 | winning bidders; administer the leases; collect bonuses, rents,
18 | royalties, and **royalty-in-kind**; and distribute the collections
19 | consistent with statutory requirements, prohibitions, and
20 | limitations governing the entity.

Deleted: shall

Comment: From Hal Steinberg:
define in the glossary.

21 c. A narrative describing future royalty rights identified for sale, **if**
22 | **applicable**. The narrative **should** provide the value of the rights
23 | identified for future sale, the location of the field(s) involved in the
24 | future sale, and the best estimate of when the rights would be
25 | sold.

Deleted: shall

26 d. A narrative describing and a display showing revenue reported by
27 | category for the reporting period **should** be presented for offshore
28 | and onshore revenues for the following categories: royalty
29 | revenue for oil and gas, rent revenue, bonus bid revenue for
30 | leases, and total revenue from all the above categories.

Deleted: earned

Deleted: shall

Deleted: earned

Deleted: earned

Deleted: earned

31 e. A narrative describing and a display showing:
32 |
33 | i. the quantity of oil and gas for each reporting period;
34 |
35 |
36 |
37 |
38 |

- 1 ii. the average of the Regional Average **First Purchase Prices**
- 2 for oil and the average of the Regional Average **Wellhead**
- 3 **Prices** for gas for each reporting period;
- 4
- 5 iii. the average **royalty rate** for oil and gas for each reporting
- 6 period;
- 7
- 8 iv. the asset value for oil and gas by the commodities and types
- 9 identified for use in calculating the federal government’s total
- 10 estimated petroleum royalties for each reporting period (see
- 11 paragraph 23); and,
- 12
- 13 v. the value of estimated petroleum royalties at the end of each
- 14 reporting period.

15
16 f. The following reconciliation of beginning and ending estimated

17 petroleum royalties asset balances:

18

Formatted: Bullets and Numbering

<u>Beginning asset balance</u>	<u>\$XX,XXX</u>
<u>Revaluation Gain / Loss Due to Changes in:</u>	
<u>Quantity</u>	<u>XXX</u>
<u>Price</u>	<u>(XX)</u>
<u>Royalty Rates</u>	<u>XX</u>
<u>Assumptions</u>	
<u>Discount Rate</u>	<u>X,XXX</u>
<u>Inflation Rate</u>	<u>XXX</u>
<u>Less:</u>	
<u>Depletion</u>	<u>(XXX)</u>
<u>Sale of future royalty streams</u>	<u>(XX)</u>
<u>Ending asset balance</u>	<u>\$XX,XXX</u>

Formatted: Indent: Left: 0.08"

19
20 This reconciliation should provide all material components of the

21 changes in the estimated petroleum royalties asset consistent with

22 the components identified in the table immediately above, if

23 applicable. Additional sub-components may be presented. The line

24 item for revaluation gains and losses should be broken out into

25 sub-components for changes in quantity; price; royalty rates, if

26 applicable; and assumptions (i.e., discount rate and inflation rate).

27

Deleted: ¶
<#>A narrative describing the estimation methodology used to calculate the value of the federal government’s estimated petroleum royalties. At a minimum, the narrative explanation should include a “plain English” explanation of the measurement method (e.g., present value) and the significant assumptions incorporated into the estimate (e.g., interest rates used to calculate present value).¶

Component Entity Required Supplementary Information (RSI)

43. The component entity responsible for reporting the federal government’s estimated petroleum royalties on its balance sheet should provide the following as RSI:

a. A narrative describing the estimation methodology used to calculate the value of the federal government’s estimated petroleum royalties. At a minimum, the narrative explanation should include a “plain English” explanation of the measurement method (e.g., present value) and the significant assumptions incorporated into the estimate (e.g., discount rates used to calculate present value, production decline curve, portion of proved reserves under federal lands, future oil and gas prices, inflation rates, etc).

b. An explanation of the significant components of the change in estimated petroleum royalties from one year to the next, the amounts associated with each type of change, and the reasons for the changes. The reasons should be explained as briefly as possible without detracting from understanding. Significant components of the change in estimated petroleum royalties include, but are not limited to, changes in quantity, price, royalty rates, discount rates, and inflation rates.

c. A reference to the source reports used to calculate the value of the federal government’s estimated petroleum royalties.

d. A narrative describing and a display showing the sales volume, the sales value, the royalty revenue, and the estimated value for royalty relief produced from federal oil and gas resources for the reporting period. To the extent that regional information is available, provide the information for each region.

Federal Receiving Entity Accounting and Reporting

44. Each federal entity that is required to receive a portion of the estimated petroleum royalties asset should disclose in the notes to its financial statements its relationship with the royalty revenue program and an estimate of the total amount of estimated petroleum royalties to be distributed to it by the component entity that is responsible for collecting royalties. The present value of the average annual share of the revenue distributed to each entity over the preceding twelve (12) months may be an acceptable basis for estimating the petroleum revenues to be distributed. Other methodologies may be acceptable.

Formatted: Bullets and Numbering

Deleted: shall

Formatted: Bullets and Numbering

Comment: From staff: For further discussion of changes, refer to Issue Paper No. 1 at Appendix 1 of the Feb issue paper.

Deleted: A narrative describing and a display showing the most current and complete information available for **technically recoverable resources**. 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.

Formatted: Bullets and Numbering

Deleted: following information for each region that was identified for use in calculating the federal government’s total estimated petroleum royalties:¶
¶
The

Deleted: earned

Comment: From H. Steinberg – Is it really necessary for general purpose external financial statements to report sales information by region?

Deleted: shall be added together in

Deleted: and reported

Deleted: ¶
A narrative describing and a display showing the following historical information about proved oil 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; new reservoir discoveries in old fields; total discoveries; estimated production; proved reserves; and change from prior year. Definitions for the ... [2]

Formatted: Bullets and Numbering

Comment: Staff note: For further discussion, see Issue Paper No. 6 at Appendix 1 of the Feb issue paper.

45. As distributions are received from the component entity responsible for collecting royalties, the federal receiving entity should record a transfer in and a corresponding increase to fund balance.

Comment: From H. Steinberg – The last two lines should read "a transfer in and a corresponding increase in fund balance." The transfer comes first.

Deleted: an

Deleted: and a corresponding transfer in

Inserted: an

Inserted: and a corresponding transfer in.¶ ... [3]

Formatted: Bullets and Numbering

Deleted: shall

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

46. The governmentwide entity should display gains and losses from changes in+ assumptions as a separate line item or line items on the statement of net cost after a subtotal for all other costs and before total cost. See the pro forma illustration in Appendix B of SFFAS 33.

47. The disclosure related to federal oil and gas resources should 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 gas for each reporting period.
 - ii. The average of the Regional Average First Purchase Prices for oil and the average of the Regional Average First Wellhead Prices for gas for each reporting period.
 - iii. The average royalty rate for oil and gas for each reporting period.
 - iv. The asset value for oil and gas by the commodities and types identified for use in calculating the federal government’s total estimated petroleum royalties for each reporting period (see paragraph 23).
 - 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.

Disclosure Requirements for Fiduciary Oil and Gas Resources

48. Fiduciary activities are defined in SFFAS 31, *Accounting for Fiduciary Activities*. Information consistent with the requirements of paragraphs 14 through 40 of this document should 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 Statement.

Deleted: shall

Deleted: standard

Effect on Existing Standards

49. This Statement 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.

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

[275.] MMS does not recognize a depletion cost for various reasons, including the fact that under present accounting standards natural resources are not recognized as an asset and depletion is not recognized as a cost. As a result, this exchange revenue bears little relationship to the recognized cost of MMS and cannot be matched against its gross cost of operations. Therefore, although the inflows are exchange revenue, they should not be subtracted from MMS's gross cost in determining its net cost of operations.

[276.] MMS collects rents, royalties, and bonuses and distributes the collections to the recipients designated by law: the General Fund, certain entities within the Government to which amounts are earmarked, the states, and Indian tribes and allottees. MMS collection activity for non-federal entities may meet the definition of fiduciary activity and, if so, should be accounted for in accordance with the requirements of SFFAS 31, Accounting for Fiduciary Activities. The amounts of revenue should be recognized and measured under the exchange revenue standards when they are due pursuant to the contractual agreement.

[277.] The rents, royalties, and bonuses transferred to Treasury for the General Fund, or to other Government reporting entities, should be recognized by them as exchange revenue. However, neither the Government as a whole nor the other recipient entities recognize the natural resources as an asset and depletion as a cost. Therefore, this exchange revenue should not offset their gross cost in determining their net cost of operations. It should instead be a financing source

Deleted: Implementation Guidance¶ The federal government's estimated petroleum royalties shall be recognized as an asset as of the beginning of the reporting period in which the standard

Deleted: s

Deleted: becomes fully 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. ¶

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.

Inserted: s

Deleted: ¶

Formatted: Bullets and Numbering

Deleted: standard

Formatted: Bullets and Numbering

1 in determining their operating results and change in net
2 position.

3 **Effective Date**

4 | **51.** The following phase-in of reporting requirements as basic information
5 provides for full implementation for reporting periods beginning after
6 September 30, 2013.

Formatted: Bullets and Numbering

7 | a. ~~These standards are~~ effective for periods beginning after September
8 30, 2010.

Deleted: This

Deleted: i

Comment: From H. Steinberg: Is that enough time?

9 b. Information should be reported as RSI for the first three years of
10 implementation (fiscal years 2011, 2012, and 2013). Until such time
11 that the information is presented as basic, information reported as RSI
12 would be presented as part of a schedule of estimated petroleum
13 royalties and not reported in the principal financial statements.

Comment: Based on question from W. Jackson regarding presentation of RSI information.

14 c. Beginning in fiscal year 2014, the required information should be
15 presented as basic information, except where specifically designated as
16 RSI (paragraph 43).

17 d. Earlier implementation is encouraged.

18
The provisions of this Statement need not be applied to immaterial items.

1 Appendix A: Basis for Conclusions

2 This appendix discusses some factors considered significant by Board members in
3 reaching the conclusions in this Statement. It includes the reasons for accepting certain
4 approaches and rejecting others. Individual members gave greater weight to some
5 factors than to others. The standards enunciated in this Statement—not the material in
6 this appendix—should govern the accounting for specific transactions, events, or
7 conditions.

8 Project History

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

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

Deleted: earned

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

31 A4. The extractive industries' activities for oil and gas can be divided into two
32 categories—upstream activities (exploration and production activities) and
33 downstream activities (transportation, refining, and marketing activities).
34 Upstream activities can be divided into the following phases:

Deleted: are

- 1 a. Prospecting¹⁶
- 2 b. Acquisition of mineral rights
- 3 c. Exploration
- 4 d. Appraisal and evaluation
- 5 e. Development
- 6 f. Production

7 A5. Downstream activities take place after the production phase of the upstream
8 activities through to the point of sale and can be divided into the following
9 phases:

- 10 a. Supply and trading
- 11 b. Shipping
- 12 c. Refining
- 13 d. Storage and distribution
- 14 e. Marketing and retail

Comment: Comment from H. Steinberg: list phases of downstream activities to be consistent with par. A4.

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

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

25 A8. This exposure draft (ED) is the Board's second request for comments on its
26 proposed requirements for accounting for federal oil and gas resources. The
27 Board released the original ED, *Accounting for Federal Oil and Gas*
28 *Resources*, on May 21, 2007. Substantive changes have been made to the
29 original ED as a result of the comments received. Discussions about the new
30 requirements as well as the changes from the original requirements are
31 disbursed throughout the remainder of this appendix.

Formatted: Bullets and Numbering

32 Overview of Federal Oil and Gas Resources

33 A9. The *Framework for Components of Federal Oil and Gas Resources*
34 (framework) presented on page 41 identifies the universe of federal oil and gas

Formatted: Bullets and Numbering

¹⁶ Prospecting usually involves researching and analyzing an area's historic geologic data and carrying out topographical, geological, and geophysical studies.

1 resources. The framework presents accounting standards requirements and
 2 the components of federal oil and gas resources (total resources). Total
 3 resources incorporate “original in-place” resources, that is, resources in the
 4 earth before human intervention.

5 | A10. The accounting standards presented in the framework include current
 6 accounting standards and proposed accounting standards for each component
 7 of federal oil and gas resources. The components are those used in the
 8 industry. Information is available in varying degrees and with varying reliability
 9 for each component. The components are first separated into “undiscovered
 10 resources” and “discovered resources.” Generally, undiscovered resources
 11 are not under lease, while, discovered resources are under lease.

Deleted: ¶

12 | Undiscovered Resources

13 | A11. The first major component of total resources is **undiscovered resources**. The
 14 undiscovered resources component is divided into the following
 15 subcomponents:

Formatted: Bullets and Numbering

- 16 a. **undiscovered non-recoverable resources**
- 17 b. **undiscovered recoverable resources**
 - 18 i. **undiscovered conventionally recoverable resources**
 - 19 ii. **undiscovered economically recoverable resources.**

20 | A12. Each component and subcomponent can be further divided between onshore
 21 and offshore resources. Onshore resources consist of resources on federal
 22 lands. Offshore resources consist of resources on the Outer Continental Shelf
 23 (OCS). This division between onshore and offshore resources is important
 24 operationally because the source and volume of information varies.

Formatted: Bullets and Numbering

25 | A13. There is no information available on undiscovered non-recoverable resources.
 26 These resources are not addressed or included in any type of assessment.
 27 Undiscovered non-recoverable resources are referred to as resources that are
 28 beyond conventional technologies to be estimated and are not assessed.
 29 However, in the realm of “original in-place” resources they may exist.

30 | A14. Information on the two subcomponents of undiscovered recoverable resources
 31 is available for offshore oil and gas resources. This information is based on
 32 national assessments performed by the Minerals Management Service (MMS)
 33 approximately every 5 years, with updates on a yearly basis for certain
 34 geographic locations. The assessment considers recent geophysical,
 35 geological, technological, and economic information and uses a geologic **play**
 36 analysis approach for resource appraisal. Information on undiscovered

1 conventionally recoverable resources and undiscovered economically
2 recoverable resources is provided in the MMS assessment.

3 **A15.** For the onshore portion of undiscovered recoverable resources, the U.S.
4 Geological Survey (USGS) formerly conducted national assessments. The last
5 comprehensive national assessment was completed by the USGS in 1995, and
6 since 2000 the USGS has been re-assessing basins of the U.S. that are
7 considered to be priorities for the new assessment rather than assessing all of
8 the basins of the U.S. As each basin is re-assessed, the assessment results
9 are added to the assessment tables, and these new values replace the
10 assessment results from 1995. The USGS assessment provides information
11 on undiscovered conventionally recoverable resources but not on undiscovered
12 economically recoverable resources like the MMS does.

13 **A16.** Under current FASAB accounting standards, there are no requirements to
14 provide or present information about the undiscovered resource components in
15 the financial statements. Information about technically recoverable resources
16 has been gathered and maintained by the Energy Information Administration
17 (EIA) in the past. However, EIA no longer reports on the technically
18 recoverable resources under federal lands. Therefore, as there is no reliable
19 source for this type of information, federal reporting on onshore and offshore
20 undiscovered recoverable resources is not required.

Deleted: Under the proposed accounting standards, information about

Deleted: would be included in the technically recoverable resources and reported as required supplementary information (RSI)

Deleted: Information about technically recoverable resources has been gathered and maintained by the EIA in the past.

Formatted: Bullets and Numbering

21 Discovered Resources

22 **A17.** The second major component of total resources is **discovered resources**.
23 The discovered resources component is divided into the following
24 subcomponents as follows:

- 25 a. **unproved reserves**
 - 26 i. **unproved possible reserves**
 - 27 ii. **unproved probable reserves**
- 28 b. **proved reserves**
 - 29 i. **proved undeveloped reserves**
 - 30 ii. **proved developed reserves**
 - 31 i) **proved developed non-producing reserves**
 - 32 ii) **proved developed producing reserves**
- 33 c. **production**
- 34

1 | A18. Under current FASAB accounting standards, there are no requirements to
 2 | provide or present information about the unproved reserves components in the
 3 | financial statements.

Formatted: Bullets and Numbering

4 | A19. Under the accounting standards proposed in the original ED, information about
 5 | onshore and offshore unproved reserves would be included in the technically
 6 | recoverable resources and reported as RSI. However, as noted in par. A16,
 7 | although information about technically recoverable resources has been
 8 | gathered and maintained by the EIA in the past, EIA no longer reports on the
 9 | technically recoverable resources under federal lands. Therefore, as there is
 10 | no reliable source for this type of information, federal reporting on unproved
 11 | reserves is not required.

Comment: From H. Steinberg: The discussion of proposed and current acctng standards for unproved reserves are separated by pars. that discuss the availability of info for proved reserves; reorder pars. Staff reordered accordingly.

12 | A20. Quantitative information in relation to onshore and offshore proved reserves,
 13 | including new discoveries, production, and adjustments is submitted to the EIA
 14 | by oil and gas well operators once a year. The due date for operators to
 15 | submit the information is April 15 for activities from the preceding calendar
 16 | year.

17 | A21. Under current accounting standards, the bonus bid, rent (collected on the lease
 18 | until oil and gas production begins), and royalty revenue (collected on
 19 | production) are accounted for as a custodial activity (i.e., an amount collected
 20 | for others) by MMS-the collecting entity. The collections and their distribution
 21 | are reported on MMS's statement of custodial activities. Component entities
 22 | receiving a distribution and the CFR of the United States government
 23 | recognize the revenue as a financing source in their respective statement of
 24 | changes in net position or statement of operations and changes in net position.

Deleted: earned

Deleted: earned

Comment: From H. Steinberg

Deleted: revenue

Deleted: its

25 | A22. Under the proposed accounting standards, the estimated federal royalty share
 26 | of proved reserves would be recognized as estimated petroleum royalties by
 27 | the component entity responsible for reporting the asset on its balance sheet.
 28 | Also, royalty revenue due would be recognized as revenue along with a
 29 | depletion expense in equal amounts on the statement of net cost. Changes in
 30 | the asset amount due to year-end valuation would be reported as a gain or loss
 31 | on the statement of net cost of the component entity responsible for reporting
 32 | the asset on its balance sheet. Also, revenue received from rent and bonus
 33 | bids would be recognized as exchange revenue on the statement of net cost.
 34 | Any expenses incurred to collect the rent and bonus bids would be included in
 35 | the operating expenses on the statement of net cost. The CFR would include
 36 | these amounts in the consolidated financial statements.

Deleted: <#>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 has been gathered and maintained by the EIA in the past. ¶ In addition, u

Deleted: earned

Deleted: collections for

Deleted: earned

37 | A23. There are no current requirements to provide or present information about the
 38 | production of oil and gas in the financial statements. However, under the
 39 | proposed accounting standards, information on the quantity and consumption

Deleted: historical

1 | of proved reserves, including the sales volume, the sales value, the amount of
 2 | royalty revenue, and the estimated value for royalty relief would be provided as
 3 | RSI.

Deleted: of proved reserves

Deleted: of proved reserves

Deleted: earned

4 | **A24.** The illustration in Appendix B: Illustration of the Components of Federal Oil and
 5 | Gas Resources provides a summary of the information presented in the
 6 | preceding paragraphs. The shaded boxes in the illustration represent the
 7 | availability of information as follows:

No quantity information available	
Technically recoverable resources quantity information provided by EIA ¹⁷	
Proved reserves quantity information provided by EIA ¹⁸	

8 |
 9 | The terms in the illustration in Appendix B are defined in the Glossary
 10 | under the subheading *Definitions of Resource and Reserve Components*
 11 | *and Subcomponents*.

13 | **Conceptual Aspects of Federal Oil and Gas Resources as an Asset for**
 14 | **Estimated Petroleum Royalties and a Liability for the Portion of Revenue to be**
 15 | **Distributed to Non-Federal Entities**

Formatted: Indent: Left: 0.2"

Deleted: Others

16 | Recognition Criteria

17 | **A25.** SFFAC 5, *Definitions of Elements and Basic Recognition Criteria for Accrual-*
 18 | *Basis Financial Statements*, states that to be recognized as an element of the
 19 | financial statements, an item must (a) meet the definition of an element of the
 20 | financial statements and (b) be measurable. The term measurable means that
 21 | a monetary amount can be determined with reasonable certainty or is
 22 | reasonably estimable.¹⁹

Formatted: Bullets and Numbering

¹⁷ Quantity information is published at the national level.

¹⁸ Quantity information is published at the national level.

¹⁹ SFFAC 5, par. 5.

1 | A26. Measurement may require the use of estimates and approximations as well as
 2 | an assessment, in a manner consistent with the attribute being measured, of
 3 | the probability that future inflows or outflows of economic benefits or services
 4 | will result from the item. Recognition decisions also incorporate the results of
 5 | assessments of the materiality and benefit versus cost of recognizing the item
 6 | measured. Thus, it is possible that an item that meets the basic recognition
 7 | criteria would not be recognized due to measurement, materiality, or cost-
 8 | benefit considerations.²⁰

9 | Asset Recognition

10 | A27. Recognition of the federal government's estimated petroleum royalties from the
 11 | production of federal oil and gas proved reserves as an asset is based on
 12 | SFFAC 5, paragraphs 18 through 35. Formatted: Bullets and Numbering

13 | A28. An asset for federal accounting purposes is a resource that embodies
 14 | economic benefits or services that the federal government controls.²¹

15 | A29. To meet the definition of an asset of the federal government, a resource must
 16 | possess two characteristics. First, it must embody economic benefits or
 17 | services that can be used in the future. Second, the government must control
 18 | access to the economic benefits or services and, therefore, can obtain them
 19 | and deny or regulate the access of other entities.²²

20 | *Oil and Gas Resources as a Federal Asset* Formatted: Indent: Left: 0.65"

21 | A30. First, the Board established which federal oil and gas resources were being
 22 | considered. Appendix B: Illustration of the Components of Federal Oil and Gas
 23 | Resources presents the oil and gas resources that were considered. The two
 24 | major components are "undiscovered resources" and "discovered resources."
 25 | All of the federal oil and gas resources qualify as federal government assets
 26 | because the government can obtain economic benefits and regulate the
 27 | access of other entities as provided under federal law. Formatted: Bullets and Numbering

28 | A31. Since all federal oil and gas resources controlled by the federal government
 29 | are assets, the Board's next step was to decide whether the federal oil and gas
 30 | resources "asset" should be recognized on a federal component entity balance
 31 | sheet. As noted in paragraph A25 above, the second criterion for recognition is
 32 | that the asset "...be measurable."

²⁰ SFFAC 5, par. 7.

²¹ SFFAC 5, par. 18.

²² SFFAC 5, par. 22.

1 A32. Estimates of the quantity of oil and gas resources other than proved reserves
 2 was available through EIA in the past. With this quantity information, a
 3 monetary measure was technically feasible and, therefore, the asset qualified
 4 for consideration for recognition. However, the Board does not believe that the
 5 information is sufficiently reliable to be recognized in a cost-beneficial manner.

Deleted: have been

Deleted: is

Deleted: s

6 A33. The EIA information on other than proved reserves is derived from sporadic
 7 and incomplete national assessments and annual submissions by oil and gas
 8 producers. This makes it particularly uncertain. In addition, since these
 9 reserves are not currently under lease, determining the royalty share may be
 10 misleading since it is a current value measure but the underlying asset may be
 11 restricted and production may never occur. For those resources that are not
 12 restricted, production may occur but the timing and amount of royalties are very
 13 uncertain. Thus, applying the same measurement technique to other than
 14 proved reserves may not result in a value that represents what it purports to
 15 represent. Therefore, federal oil and gas resources not yet in the 'proved
 16 reserves' category would not be recognized on the federal balance sheet due
 17 to concerns regarding reliability of the proposed measure.

Comment: From H. Steinberg: The two pars. that address the unreliability of other than proved reserves info. should be contiguous. Staff moved pars. accordingly.

18 A34. SFFAC 1, *Objectives of Federal Financial Reporting*, provides the following
 19 with respect to reliability:

Deleted: However, information on these quantities would be provided as RSI.

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

36 A35. Concerning the proved oil and gas reserves from federal oil and gas resources,
 37 the Board believes that both the quantity and the estimated federal royalty
 38 share would be reliable. Thus, in this case, since the quantity of the estimated
 39 federal proved oil and gas reserves can be reliably estimated and converted to
 40 monetary terms (estimated federal royalty share), the Board believes the

Formatted: Bullets and Numbering

Deleted: royalty share

Comment: From H. Steinberg: Clarify what is meant by "quantity of the estimated royalty share can be reliably estimated and converted to monetary terms."

1 estimated federal royalty share of proved oil and gas reserves should be
 2 recognized on the balance sheet.

3 Measurement Attributes and Methods Considered

4 **A36.** Concerning the dollar amount to be recognized for the estimated federal royalty
 5 share of proved reserves, the Board considered various measurement
 6 attributes²³ and methods, including the following:

7
 8 **A37.** Historical cost (historical proceeds) – The amount of cash, or its equivalent,
 9 paid to acquire an asset, commonly adjusted after acquisition for amortization
 10 or other allocations (SFAC 5, par. 67). ‘Historical cost’ was not a feasible
 11 option for valuing the oil and gas reserves because there is no ‘historical
 12 exchange price’ for the oil and gas reserves controlled by the federal
 13 government.

14
 15 **A38.** Fair value – When market transactions are available, fair value is the same as
 16 market value. Fair value is the price that would be received to sell an asset or
 17 paid to transfer a liability in an orderly transaction between market participants
 18 at the measurement date (SFAS 157, par. 5). Information needed to estimate
 19 fair value is not available as there are no current transactions between market
 20 participants involving the sale of the federal royalty share for proved oil and gas
 21 reserves.

22
 23 **A39.** Net realizable (settlement) value – The total non-discounted amount of cash, or
 24 its equivalent, into which an asset is expected to be converted in due course of
 25 business less direct costs, if any, necessary to make that conversion (SFAC 5,
 26 Par 67). The ‘net realizable value’ (NRV) requires a reasonable estimate of
 27 future flows (receipts and costs) associated with converting assets to cash.
 28 However, it may be difficult to reliably estimate the amount of the future flows
 29 of the federal royalty share for proved oil and gas reserves due to volatile
 30 fluctuations in the first purchase price for oil and wellhead price for gas.

31
 32 **A40.** Present (or discounted) value of future cash flows – The present or discounted
 33 value of future cash inflows into which an asset is expected to be converted in
 34 due course of business less present values of cash outflows necessary to
 35 obtain those inflows (SFAC 5, Par 67). An estimate of the ‘present (or
 36 discounted cash) value’ of the estimated federal royalty share appeared to be
 37 most appropriate because the asset will be converted in future periods.

Deleted: ¶
 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.¶

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Deleted: Nor are there current transactions between market participants for the sale of rights to comparable future revenue streams.

Formatted: Bullets and Numbering

Deleted: cannot be reliably estimated for various reasons. The amount cannot be reliably estimated

Deleted: Reasons for these variations include:

Deleted: The permitting process for exploration, development, and production activities.¶
 <#>The lessee’s budget.¶
 <#>Other projects the lessee is focusing on.¶
 <#>The geological make-up of the earth.¶
 <#>The depth of the water or the depth of the wells for offshore wells.¶
 <#>The uncertainties of each well.¶
 <#>New discoveries.¶
 <#>Improved technology.¶
 <#>The economy and price volatility.¶
 Production incentives provided by the federal government.

Formatted: Bullets and Numbering

²³ Measurement attribute – the traits or aspects of an element that can be quantified in monetary units with sufficient reliability (adapted from Statement of Financial Accounting Concepts (SFAC) 5: Recognition and Measurement in Financial Statements of Business Enterprises, as amended, par. 65).

1 However, the 'present (or discounted cash) value' method poses measurement
2 challenges because:

- 3
4 a. It is difficult to estimate the timing of future inflows.
5 b. The discount rate should be commensurate with the riskiness of the
6 stream and each well might be viewed as having a unique level of risk.
7 c. Prices are subject to fluctuation, making the amount of future inflows
8 volatileA39.
9 d. It is difficult to estimate the time from when a lease is signed until
10 production begins (from 3 years to 20 years or more) and how long a
11 well will be productive.
12

13 **A41.** Based on the above, the Board had previously determined that none of the
14 measurement methods or attributes currently used in practice was a feasible
15 measure of the estimated federal royalty share for proved oil and gas reserves.
16 However, after reviewing the results of the field testing performed by the
17 Department of the Interior (DOI) and talking with DOI representatives about the
18 methodology that has been developed, the Board determined that present
19 value might be a feasible measure if the challenges presented in paragraph
20 A40 above can be reasonably overcome.
21

22 *Asset Valuation Methodology*

23
24 **A42.** The Board believes that the detailed estimation methodology for valuing oil and
25 gas natural resources should be developed by federal entities rather than
26 centrally by the Board. In an environment heavily affected by changes in
27 prices, technological advancements, economic and operating conditions, and
28 known geological, engineering, and economic data, estimation methodologies
29 may need to be regularly updated to reflect changing economic and
30 technological conditions. Sources of information that were once available to
31 preparers may be replaced or become obsolete. On the other hand, new and
32 more reliable data sources may become available. Permitting the preparers
33 flexibility in developing an estimation methodology that keeps pace with the
34 environment will prevent the accounting standards from becoming outdated.
35

36 **A43.** EIA has been used as the source of information on proved reserves data in the
37 past and may prove to continue to be the appropriate source for such
38 information in the future. However, the Board has chosen not to explicitly
39 designate EIA as the source of information in an attempt to prevent the
40 standards from becoming outdated if EIA were to stop reporting the minimum
41 information necessary to calculate the estimated petroleum royalties asset. In
42 addition to dating the standards, an explicit designation of the source of

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Comment: From H. Steinberg – Is "outdated" the right word? The absence of source information would make a standard outdated as much as incapable of being applied.

1 information would prevent the preparer from fully complying with the standards
2 if the source were no longer available at some point in the future.

3
4 *Change in Methodology after the Initial Year of Implementation*

← --- Formatted: Indent: Left: 0.65"

5
6 A44. The net effect of a change in methodology after the initial year should be
7 accounted for as a change in accounting estimate effected by a change in
8 accounting principle.

← --- Formatted: Bullets and Numbering

9
10 A45. A change in accounting estimate effected by a change in accounting principle
11 is a change in accounting estimate that is inseparable from the effect of a
12 related change in accounting principle. An example of a change in estimate
13 effected by a change in principle is a change in the method of depreciation,
14 amortization, or depletion for long-lived, nonfinancial assets (SFAS 154, par.
15 2e).

← --- Formatted: Bullets and Numbering

16
17 A46. Distinguishing between a change in an accounting principle and a change in an
18 accounting estimate is sometimes difficult. In some cases, a change in
19 accounting estimate is effected by a change in accounting principle. One
20 example of this type of change is a change in method of depreciation,
21 amortization, or depletion for long-lived, nonfinancial assets (hereinafter
22 referred to as depreciation method). The new depreciation method is adopted
23 in partial or complete recognition of a change in the estimated future benefits
24 inherent in the asset, the pattern of consumption of those benefits, or the
25 information available to the entity about those benefits. The effect of the
26 change in accounting principle, or the method of applying it, may be
27 inseparable from the effect of the change in accounting estimate. Changes of
28 that type often are related to the continuing process of obtaining additional
29 information and revising estimates and, therefore, are considered changes in
30 estimates for purposes of applying this Statement (SFAS 154, par. 20).

← --- Formatted: Bullets and Numbering

31
32 A47. Like other changes in accounting principle, a change in accounting estimate
33 that is effected by a change in accounting principle may be made only if the
34 new accounting principle is justifiable on the basis that it is preferable. For
35 example, an entity that concludes that the pattern of consumption of the
36 expected benefits of an asset has changed, and determines that a new
37 depreciation method better reflects that pattern, may be justified in making a
38 change in accounting estimate effected by a change in accounting principle
39 (SFAS 154, par. 21).

← --- Formatted: Bullets and Numbering

- 1 | *Use of Regional Data to Value the Federal Asset “Estimated Petroleum*
2 | *Royalties”* ← **Formatted:** Indent: Left: 0.65”
- 3 | **A48.** The Board believes that the most relevant, reliable, and cost-beneficial ← **Formatted:** Bullets and Numbering
4 | measurement of “estimated petroleum royalties” would be obtained by using
5 | regional information. The Board believes this approach would provide
6 | conservative, representative regional values of estimated petroleum royalties
7 | without having to calculate the value on a field-by-field basis. The Board
8 | believes it would not be practicable to make calculations on a field-by-field
9 | basis. There are more than 60,000 leases maintained by the DOI with
10 | approximately 115,000 producing wells.
- 11 | Liability Recognition
- 12 | **A49.** Recognition of royalty distributions to non-federal entities as a liability is based ← **Deleted:** others
13 | on SFFAC 5 paragraphs 36 through 48. ← **Formatted:** Bullets and Numbering
- 14 | **A50.** A liability is a present obligation²⁴ of the federal government to provide assets
15 | or services to another entity at a determinable date, when a specified event
16 | occurs, or on demand.²⁵
- 17 | **A51.** A liability of the federal government has two essential characteristics. First, a
18 | liability constitutes a present obligation to provide assets or services to another
19 | entity. Second, either a law or an agreement or understanding between the
20 | government and another entity identifies conditions or events that will
21 | determine when the obligation will be settled.²⁶
- 22 | **A52.** In paragraph 17, the Board proposes that the federal government’s estimated
23 | petroleum royalties be recognized as an asset on the balance sheet of the
24 | component entity that is responsible for collecting royalties. The asset’s value
25 | would be based on the royalty share of the federal oil and gas resources
26 | classified as “proved reserves.” In addition to the royalties that the component
27 | entity collects on proved reserves that are produced, it also collects lease sale
28 | and rent revenue from federal government oil and gas leases. The component
29 | entity distributes nearly all of these proceeds to others (e.g., the general fund of
30 | the U.S. Treasury, other federal agencies, and state governments) in ← **Deleted:** states
31 | accordance with legislated allocation formulas. The component entity also

²⁴ The term obligation is used in this Statement 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.

²⁵ SFFAC 5, par. 39.

²⁶ SFFAC 5, par. 41.

1 receives a very small portion of the revenue collected to fund its operations.
 2 The amount used to fund its operations is legislated by Congress as part of the
 3 component entity's annual appropriation. For example, the amount received by
 4 the component entity was approximately one percent (1%) of annual revenues
 5 collected in 2005.

6 A53. The Board considered and agreed that a liability for revenue distributions to
 7 others should be recognized in conjunction with the recognition of an asset for
 8 estimated petroleum royalties. The Board believes a liability for revenue
 9 distributions to others should be recognized because nearly all of the revenue
 10 from royalties, lease sales, and rent are ultimately distributed to others (e.g.,
 11 the general fund of the U.S. Treasury, other federal agencies, and state
 12 governments). As the proceeds are distributed, the liability would be reduced.
 13 In addition, upon consolidation, the portion of the liability related to other
 14 federal agencies and the general fund of the U.S. Treasury would be
 15 eliminated so that the balance sheet for the government as a whole reports
 16 only the liability for amounts allocated to non-federal entities.

Deleted: an offsetting

Deleted: an offsetting

Deleted: the states

17 A54. The Board believes that if a liability for revenue distributions to others was not
 18 established, the component entity's and the federal government's net position
 19 would be overstated.

20 A55. Conceptually, it would be appropriate for the component entity to record a
 21 liability for the revenue to be distributed to both federal and non-federal parties.
 22 However, in its response to the field test questionnaires, the Department of the
 23 Interior (DOI) field test team notes that each designated federal recipient would
 24 be required to record a corresponding receivable and transfer in their
 25 statements, with eliminations between entities to prevent double counting
 26 government wide. The field test team notes that this accounting becomes
 27 especially critical at quarter-ends and at fiscal year-end, where late
 28 adjustments required to accruals that are deemed related to oil and gas
 29 revenue will also require late adjustments by all downstream recipients, thus
 30 significantly hampering entities' ability to meet accelerated financial reporting
 31 due dates and potentially giving rise to audit findings.

Formatted: Bullets and Numbering

32 A56. Recognizing that the federal government's current environment results in a
 33 continuing strain on resources, the Board has become even more sensitive to
 34 developing accounting requirements that serve to provide meaningful
 35 information to financial statement users while trying to avoid requirements that
 36 are complied with merely for the sake of compliance.

37 A57. The original ED requirements would result in each of the receiving federal
 38 entities recognizing an account receivable and a transfer in their financial
 39 statements for the initial asset entry. Then, as the asset is subsequently

1 revalued or adjusted by DOI or its auditors, the receiving federal entities would
2 need to adjust their accounts receivable and transfer accounts. In addition, the
3 intragovernmental elimination entries would need to be adjusted as well. This
4 would be a lot of last minute adjusting for amounts that would be eliminated
5 from the CFR. However, if the receivable entries were not made, the receiving
6 entities would not be including these assets in their financial statements. The
7 Board reconsidered the value of having the federal component entities record
8 the receivable and transfer in their financial statements.

9 A58. Accounts receivable arise from claims to cash or other assets (SFFAS 1, par.
10 40). The purpose of recognizing accounts receivable for accrual-basis
11 accounting is to recognize a resource that embodies economic benefits or
12 services in the period that it becomes measurable (SFFAC 5, pars. 5 and 18).
13 While the Board has decided that the estimated petroleum royalties asset upon
14 which the receivable would be based can be reasonably estimated, it is
15 doubtful that the federal receiving entity management would find much
16 decision-useful information with the recognition of a receivable that would be
17 extremely volatile and could not be relied upon for short or long-term budget
18 decisions. In addition, it is doubtful that the financial statement users would
19 find more value in recognition of a receivable on the face of the financial
20 statement as opposed to a disclosure of an estimated amount in the notes to
21 the financial statements. On the contrary, revaluations of the asset that result
22 in large inflows or outflows to the receiving entity in any given year would
23 require a detailed explanation to satisfy the user.

24 A59. The Board revised the requirements from the original ED so that only a liability
25 for revenue to be distributed to non-federal entities (e.g., state governments) is
26 required to be recognized while each federal receiving entity must disclose in
27 the notes to its financial statements its relationship with the royalty revenue
28 program and an estimate of the total amount of estimated petroleum royalties
29 to be distributed to it.

30 **Reporting the Gains and Losses from Changes in Assumptions and Selecting** 31 **Discount Rates**

32 A60. SFFAS 33, *Pensions, Other Retirement Benefits, and Other Postemployment*
33 *Benefits: Reporting the Gains and Losses from Changes in Assumptions and*
34 *Selecting Discount Rates and Valuation Dates*, requires that gains and losses
35 from changes in long-term assumptions used to estimate federal employee
36 pension, other retirement benefit (ORB), and other postemployment benefit
37 (OPEB) liabilities should be displayed on the statement of net cost separately
38 from other costs. This display provides more transparent information regarding
39 the underlying costs associated with certain liabilities. SFFAS 33 also provides

Formatted: Bullets and Numbering

standards for selecting the discount rate assumption and valuation date for pension, ORB, and OPEB liabilities.

A61. SFFAS 33 does not preclude entities from displaying or disclosing any information about the effect of changes in any assumptions with regard to other types of activities. The original SFFAS 33 ED had proposed a broad scope; however, although in principle a broader application was desirable, the Board decided to limit the standards to federal employee pension, ORB, and OPEB liabilities. This decision was based on the Board's desire to address more immediately its primary concern, which is to display the effect of assumption changes on employee compensation liabilities. Respondents had requested more guidance regarding how the standards would apply to other long-term assumptions; the Board believed that developing additional guidance would significantly delay implementation of SFFAS 33.

Formatted: Bullets and Numbering

Comment: From H. Steinberg – I wonder who decided that “in principle, a broader application of the provisions of SFFAS 33 was desirable.” If it was, the broader application would have been encompassed in SFFAS 33. I suggest removing the phrase. Staff note: the ED issued for comment did include a broader scope but the board limited the scope in the final standard to get the standard issued more quickly to address pension, ORB, and OPEB liabilities.

A62. The Board believes that it would be appropriate to apply the guidance in SFFAS 33 to long-term assumptions about oil and gas in order to increase the usefulness of reported operating results when the volatility of projections results in large variations in annual net cost from year to year.

Comment: From H. Steinberg: describe why the Board believes that or delete the par.

Comment: From H. Steinberg – In retrospect, I think the paragraph should be deleted entirely. There is no guidance in SFFAS regarding long-term assumptions applicable to oil and gas. Staff note: In applying SFFAS 33 to oil and gas in this draft ED, the board would be stating that it believes it would be appropriate to apply SFFAS 33 and is proposing guidance on long-term assumptions applicable to oil and gas.

Formatted: Bullets and Numbering

Future Rights to Royalty Streams Identified for Sale

A63. 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.

A64. The value of the disclosed future royalty rights identified for sale is based on the specific field identified for sale. Because the fields are known, this provides a more field specific value for the rights identified to be sold.

A65. 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 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

1 is used to reduce the estimated petroleum royalties since the values of a
 2 specific field are known and the value of the future royalty rights sold can be
 3 more accurately calculated, which would provide a more realistic gain or loss
 4 on the sale. In addition, the liability for revenue distributions to non-federal
 5 entities should be adjusted by the amount of the gain or loss on the sale, if any,
 6 and reduced when the sale proceeds are distributed.

Deleted: others

7 Disclosures

8 **A66.** The Board proposes that various types and amounts of information be
 9 disclosed in the notes or provided as RSI. For example, one proposed
 10 disclosure would require a narrative describing and a display showing revenue
 11 reported by category for the reporting period. That is, royalty revenue for oil
 12 and gas, rent revenue, bonus bid revenue for leases, and total revenue. The
 13 proposed RSI includes sales volume, the sales value, the royalty revenue, and
 14 the estimated value for royalty relief for oil and gas produced from federal oil
 15 and gas resources for the reporting period. This information would be
 16 presented for each region, to the extent that regional information is available.

Formatted: Bullets and Numbering

Deleted: earned

Deleted: earned

Deleted: earned

Deleted: earned

Deleted: earned

Comment: From H. Steinberg – Is it really necessary for general purpose external financial statements to report sales information by region?

17 Original Exposure Draft

18 **A67.** The original exposure draft (ED), *Accounting for Federal Oil and Gas*
 19 *Resources*, was issued May 21, 2007 with comments requested by September
 20 21, 2007. However, because the Board received a request for the comment
 21 period to be extended and because few responses had been received, the
 22 Board agreed to extend the comment period until January 11, 2008.

Deleted: on a regional basis. Proposed RSI also includes a narrative describing and a display showing detailed historical information for the preceding ten calendar years.

Formatted: Bullets and Numbering

23 **A68.** Upon release of the original ED, notices and press releases were provided to
 24 The Federal Register, *FASAB News*, *The Journal of Accountancy*, *AGA Today*,
 25 *the CPA Journal*, *Government Executive*, *the CPA Letter*, *Government*
 26 *Accounting and Auditing Update*, the CFO Council, the Presidents Council on
 27 Integrity and Efficiency, Financial Statement Audit Network, the Federal
 28 Financial Managers Council, and committees of professional associations
 29 generally commenting on exposure drafts in the past.

30 **A69.** This broad announcement was followed by direct mailings or e-mails of the
 31 original ED to:

- 32 a. relevant congressional committees (Senate Committee on Energy and
 33 Natural Resources, Senate Committee on Finance, Senate Committee on
 34 Indian Affairs, House Committee on Financial Services, House Committee
 35 on Natural Resources);

- 1 b. federal agencies (Office of Financial Management, Department of the
2 Interior (DOI); Office of the Special Trustee (OST), DOI; Office of Financial
3 Management, Department of Energy; Reserves and Products Division,
4 Office of Oil and Gas, Energy Information Administration (EIA),
5 Department of Energy; Office of the Chief Accountant, Securities and
6 Exchange Commission (SEC));
- 7 c. public interest groups (National Congress of American Indians (NCAI)
8 President and Area (Regional) Vice Presidents); and,
- 9 d. oil and gas industry companies/professional organizations ((World
10 Petroleum Congress (WPC), American Petroleum Institute (API), Society
11 of Petroleum Engineers (SPE), Ryder Scott Company, National Petroleum
12 Council (NPC), International Energy Agency (IEA), British Petroleum (BP),
13 Royal Dutch Shell, Chevron, Exxon Mobil)).
- 14 A70. To encourage responses, reminder notices were provided on September 12,
15 2007, and January 9, 2008, to the FASAB listserv. In addition, staff contacted
16 professional associations and affected agencies directly.

17 Comment Letters

18 A71. Eight comment letters were received from the following sources:

	FEDERAL (Internal)	NON-FEDERAL (External)
Users, academics, others		4
Auditors	1	
Preparers and financial managers	3	

19 A72. The following points present a high-level summary of the comments received:

- 20
- 21 a. The majority of respondents agreed with the overall concept of
22 recognizing an asset for the federal government's natural resources and a
23 liability for the related royalty revenues designated to be distributed to
24 others.
- 25 b. Two of the eight respondents stated that ~~standards~~ on federal natural
26 resources should include all federal natural resources and not be limited to
27 only oil and gas resources.
- 28 c. One of the eight respondents commented on the complex nature of the
29 original ED.

- 1 d. No respondents supported the use of the probabilistic method of
2 estimation as proposed in the alternative view of the original ED.
- 3 e. Two respondents supported the use of present value or fair value with
4 discounting (similar to the alternative view proposal) instead of the
5 valuation method as proposed in the original ED that utilizes the average
6 first purchase or wellhead price.
- 7 f. The majority of respondents agreed that the numerous disclosures
8 proposed in the original ED appeared excessive and might not pass a
9 cost/benefit test.
- 10 g. There was general support for royalty relief disclosures.
- 11 h. Of the five respondents that directly addressed the question on fiduciary
12 disclosures, four stated that the cost of such disclosures would outweigh
13 any perceived benefits.
- 14 i. The majority of respondents supported the recommendation for more
15 limited disclosures in the CFR. However, one respondent stated that
16 because natural resources are sovereign assets, the major disclosures
17 would more appropriately appear in the CFR and not agency financial
18 statements.

19 | A73. The Board did not rely on the number in favor of or opposed to a given
20 position. Information about the respondents' majority view is provided only as a
21 means of summarizing the comments. The Board considered the arguments in
22 each response and weighed the merits of the points raised.

Formatted: Bullets and Numbering

23 Field Testing

24 | A74. In addition to the comment letters received on the original ED, the Board also
25 considered the results of a field test of the proposed standards performed by a
26 DOI field test team. The field test team consisted of Minerals Management
27 Service (MMS) Offshore Minerals Management Economics and Resource
28 Evaluation experts and petroleum engineers; Bureau of Land Management
29 petroleum engineers and resource evaluation experts; and MMS Custodial
30 Reporting Branch senior accountants with expertise in financial reporting.

Formatted: Bullets and Numbering

31 | A75. Field tests are part of FASAB's due process and help FASAB to establish
32 effective standards. Participating federal entities volunteer to go through the
33 exercise of "implementing" the proposed standards s as if they were in place and
34 then provide feedback to FASAB regarding the process. Field tests can
35 proactively identify potential problems related to the implementation of

Deleted: it

- 1 proposed standards and allow FASAB to gather valuable information about
2 implementation costs.
- 3 | A76. The field test team presented the Board with a number of significant
4 considerations, including the lack of availability of quantity information on
5 proved reserves under federal lands. The original ED had proposed that the
6 valuation of oil and gas resources be based on information to be provided by
7 | EIA, on quantity of proved reserves under federal lands. However, this
8 information has not been made available as of the date of this revised ED, and
9 does not appear to be forthcoming.
- 10 | A77. In addition to the reliance on proved reserves data required to be provided by
11 EIA, the field test team noted a number of other concerns, including:
- 12 | a. the desire to divide proved reserves by type of commodity (e.g., crude oil,
13 lease condensate, and natural gas) and compute the asset value
14 separately;
- 15 b. the need to develop a methodology for determining what portion of all
16 proved reserves fall under federal domain;
- 17 c. the need to exclude royalty relief volumes and estimate the value of
18 commodities received in kind and delivered to the Department of Energy
19 to fill the Strategic Petroleum Reserve;
- 20 d. the effect of intermediate production between the effective date of the
21 reserves estimate and the effective date of the booked value;
- 22 e. the effect of estimates such as the royalty accrual and prior year
23 production adjustments made in the current year;
- 24 | f. how to distinguish between long and short-term liabilities for the
25 associated liability for revenue distributions to others;
- 26 g. appropriate treatment of interest payments related to oil and gas or
27 | commodities other than oil and gas once the custodial provisions are
28 deleted from SFFAS 7 (paragraphs 45, 275, 276, and 277);
- 29 h. the impact of material intragovernmental transactions and eliminations on
30 the year-end reporting process; and,
- 31 i. the need to revise all, or almost all, of the existing posting models in the
32 accounting system.

Deleted: the Energy Information Administration (

Deleted:)

Deleted: need

Deleted: other

1 | A78. The field test team also completed a field test questionnaire using a present
2 | value approach. This questionnaire included a lot of the same concerns as
3 | noted in paragraphs A76 and A77 above. In addition, the present value
4 | approach also incorporated present value calculations for factors such as the
5 | present value of royalties received over time, estimates of future gas prices,
6 | transportation allowances, and discount and inflation rates.

Formatted: Bullets and Numbering

7 | A79. In both estimates (the ED view as well as the present value view), the field test
8 | team used share of production as a proxy for share of proved reserves. One of
9 | the members expressed concerns about the use of production as a proxy for
10 | underlying reserves since it assumes (1) the same percentage of reserves are
11 | brought to market each year from all locations (or at least, on average between
12 | federal and non-federal) and (2) too much year to year variance in production
13 | patterns makes underlying reserve estimates fluctuate by an equal amount.

14 | A80. Staff asked an oil and gas analyst at the Congressional Budget Office for his
15 | thoughts on the methodology. He responded that he understands the concern
16 | with the first assumption because it is likely that not the same fraction of
17 | reserves will be accessed in each year. However, he stated that averaging
18 | between federal and non-federal would control for some of that variance,
19 | though it is not possible to know just how much. He stated that this simplifying
20 | assumption is fairly reasonable given the approximate nature of the analysis.
21 | The analyst noted that with the second assumption, the variance might be
22 | eliminated or reduced by using a moving average rather than a year to year
23 | measure. For example, a 5-year or 10-year moving average of total federal
24 | production over total production would control some of the yearly differences
25 | between federal and non-federal.

26 | A81. The field test questionnaires were extremely useful in helping the Board
27 | determine the focus of the current ED.

28 | Discussion with DOI Representatives

29 | A82. In addition to the Board's consideration of the comment letters received and
30 | the field test questionnaires, three members of the field test team and two
31 | representatives from the DOI Office of the Secretary met with the Board at the
32 | October 23, 2008, meeting to discuss issues raised in its comment letter on the
33 | original ED and the related field test questionnaires.

Formatted: Bullets and Numbering

34 | A83. At that meeting, the DOI representatives indicated that they would be open to
35 | having less detailed implementation guidance in the standards if they were
36 | given a longer implementation period (two to three years) with a phase-in from
37 | RSI to basic, and the ability to return to FASAB for implementation guidance if
38 | a reasonable methodology could not be agreed to by the auditors.

1 Significant Changes Made to the Original Exposure Draft

2 | **A84.** The significant changes made to the original ED as a result of the Board's
3 consideration of the comments received, the field test questionnaires, and
4 discussions with DOI representatives are summarized below:

Formatted: Bullets and Numbering

5 a. Removed specific reference to "proved oil and lease condensate, **natural**
6 **gas plant liquids (NGPLs)**, and gas reserves"; the revised ED refers
7 more broadly to "proved oil and gas reserves." Further breakdown by
8 commodity and type of oil and gas will be considered by the federal entity
9 as part of the estimation methodology.

Deleted: now

10 b. Removed detailed asset valuation implementation guidance. Federal
11 entities are provided flexibility in developing the estimation methodology
12 for valuing oil and gas natural resources. In an environment heavily
13 affected by changes in prices, technological advancements, economic and
14 operating conditions, and known geological, engineering, and economic
15 data, estimation methodologies may need to be regularly updated to
16 reflect changing economic and technological conditions. The Board
17 believes that the detailed estimation methodology for valuing oil and gas
18 natural resources should be developed by federal entities rather than
19 centrally by the Board.²⁷ The Board reached this conclusion based on
20 discussions about recent changes that have occurred since the original
21 ED was issued and the need to continually update the accounting
22 standards as a result of volatile conditions in the oil and gas industry. The
23 Board also considered DOI's willingness to develop the methodology and
24 work with the auditors to phase in the required reporting from RSI to basic
25 over a period of two or three years and return to FASAB only on issues
26 that could not be resolved with the auditors.

Deleted: <#>Simplified the detailed pro forma transactions; removed excess detail on how values were derived.¶

27 c. Removed the illustrative disclosure and RSI presentations.

Formatted: Bullets and Numbering

28 d. Selected present value as the measurement method.

29 e. Stated that the preferred measurement method for valuing the federal
30 government's estimated petroleum royalties is the present value of future
31 federal royalty receipts on proved reserves; however methods for
32 measuring fair value may be acceptable if it is not reasonably possible to
33 estimate present value.

Deleted: Provided federal entities with the opportunity to compute the federal government's estimated petroleum royalties by "multiplying the estimated quantity of proved oil and gas reserves under federal lands by the average first purchase price for oil or average wellhead price for gas and the effective average royalty rate by region" if it is not reasonably possible to estimate the present value of future federal royalty receipts on proved reserves. Other methodologies are deemed acceptable

Deleted: another

Deleted: ology

Inserted: ology

²⁷ Estimates that do not lead to material misstatements are acceptable without guidance from the Board.

- 1 f. Permitted a change in methodology (see paragraphs 25 through 26) that
 2 is to be accounted for as a change in estimate effected by a change in
 3 principle.
- 4 g. Revised the component entity RSI disclosures.
- 5 h. Revised the requirement to recognize a liability for revenue distributions to
 6 others (e.g., the general fund of the U.S. Treasury, other federal agencies,
 7 and state governments) to only recognize the portion of the revenue to be
 8 distributed to non-federal entities (e.g., state governments).
- 9 i. Included a discussion of the classification of the liability for revenue to be
 10 distributed to non-federal entities as long-term vs. short-term.
- 11 j. Incorporated SFFAS 33 guidance for displaying gains and losses from
 12 changes in assumptions and selecting discount rates.
- 13 k. Incorporated accounting and disclosure requirements for the federal
 14 receiving entities.
- 15 l. Updated the effective date of the standards to provide for a three-year
 16 phase-in from RSI to basic information.
- 17 m. Moved the illustration of the components of federal oil and gas resources
 18 to an appendix by itself.
- 19 n. Updated the basis for conclusions.
- 20 o. Updated questions for respondents to request feedback on changes made
 21 to the original exposure draft.
- 22 p. [TBD based on discussion of other issues – fiduciary reporting, custodial
 23 reporting for other commodities, etc]

Deleted: "Once established, the estimation methodology should be consistently followed and disclosed in the financial reports. If environmental or other changes would provide for the development of an improved methodology, the nature and reason for the change in methodology, as well as the effect of the change, should be disclosed."

Deleted: long-term vs. short-term liability classification, detailed component entity RSI,

[This page intentionally left blank.]

1 Appendix B: Illustration of the Components of Federal Oil and Gas Resources

Accounting Standards	Components of Federal Oil and Gas Resources							
	Undiscovered Resources				Discovered Resources			
	Undiscovered Non-Recoverable Resources	Technically Recoverable Resources			Proved Reserves			Production
		Undiscovered Recoverable Resources		Unproved Reserves		Proved Reserves		
	Undiscovered Conventionally Recoverable Resources	Undiscovered Economically Recoverable Resources	Unproved Possible Reserves	Unproved Probable Reserves	Proved Undeveloped Reserves	Proved Developed Reserves		
					Proved Developed Non-Producing Reserves	Proved Developed Producing Reserves		
Current Accounting Standards	Bonus bid, rent, royalty revenue accounted for as custodial activity and recognized as a financing source on the CFR statement of operations and changes in net position							
Proposed Accounting Standards			<ul style="list-style-type: none"> Recognize bonus bid and rent revenues as exchange revenue on SNC²⁸ 	<ul style="list-style-type: none"> Recognize <u>projected</u> federal royalty share on BS²⁹ Recognize gains/losses on SNC Provide disclosures for Proved Reserves 	<ul style="list-style-type: none"> Recognize <u>royalty revenues as revenue and depletion expense on SNC</u> Provide RSI/ Disclosure Information 			

- Comment:** From H. Steinberg: Aren't royalties retained also reported as a financing source on DOI's SoCNP? Staff response: Amount flows through as an annual appropriation to fund operations; shows up on SoCNP as appropriations received, royalties are not technically "retained" in the true sense of the word.
- Comment:** From H. Steinberg
- Deleted:** Provide RSI¶ Information for Undiscovered Recoverable Resources
- Deleted:** ¶ Recognize bonus bid and rent revenue as exchange revenue on SNC
- Deleted:** <#>Recognize royalty revenues as revenue and depletion expense on SNC¶
- Deleted:** Provide RSI Information for Unproved Reserves
- Deleted:** ¶ Quantitative and Financial

²⁸ statement of net cost
²⁹ balance sheet

[This page intentionally left blank.]

Deleted: And

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 are based on hypothetical numbers for purposes of simplification. 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. Budgetary and additional nominal account entries would be made by the collecting entity to track and report on greater detail than is illustrated in this appendix. 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. In addition, a greater degree of detail and certain reclassifications would occur in practice.

Comment: From H. Steinberg: It would be helpful to precede the entries with a brief narrative of the transaction that occurred in the entity. Staff is expanding the entries back to their original state from the May 2007 ED.

Comment: Included in field test response; see appendix 2, comment number 1.

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.

Deleted: is

Deleted: At the beginning of the fiscal year for which the accounting standard

Deleted: s

Deleted: for oil and gas resources

Deleted: are

Deleted: is effective, the following transaction is recorded by the component entity responsible for collecting royalties.

Inserted: is

Deleted: others

1. Record initial value of estimated petroleum royalties and the liability for revenue distributions to non-federal entities.

The initial value of estimated petroleum royalties used in this pro forma transaction is \$150,677,667, a hypothetical number used for illustrative purposes only. The actual value of the federal government's estimated petroleum royalties would be calculated on a regional basis and should approximate the present value of future royalty receipts on proved reserves known to exist as of the reporting date.

The illustrative pro forma entry to record the initial value of the federal government's estimated petroleum royalties as well as the liability for revenue to be distributed to non-federal entities is presented below. The asset's value would be the royalty share of the federal oil and gas resources classified as "proved reserves." The liability for revenue to be distributed to non-federal entities would be for the royalty share of the federal oil and gas resources classified as "proved reserves" designated to be distributed to non-federal entities, e.g., state governments. The proposed treatment of the distribution of revenue to non-federal entities creates a non-federal liability for the component entity responsible for collecting royalties.

Deleted: the states

The net effect of recognizing an asset and establishing a liability at the beginning of the reporting period would be 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 statement of changes in net position for the component entity responsible for collecting royalties in the period the change is made.

Deleted: and

Deleted: and other federal entities

Inserted: and other federal entities. For this illustration, 85 percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting royalties and to other federal component entities based on the average distribution for 2005. To record the liability for revenue to be distributed to others

To obtain the value of the prior period adjustment, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the component entity responsible for collecting royalties and other federal entities. For this illustration, 85 percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting

royalties and to other federal component entities based on the average distribution for 2005. To record the liability for revenue to be distributed to non-federal entities, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to state governments and other non-federal entities. For this illustration, 15 percent was used as an average annual share of the revenue distributed to state governments and other non-federal entities based on the average distribution for 2005. These calculations are presented below:

$$\begin{aligned} & \$150,677,667 \times .85 = \$128,076,017 \text{ (federal portion)} \\ & \$150,677,667 \times .15 = \$22,601,650 \text{ (non-federal portion)} \end{aligned}$$

Dr Estimated Petroleum Royalties	150,677,667	
Cr Prior Period Adjustment: Change in Accounting Principle		128,076,017
Cr Liability for Revenue Distribution to Others – Non-Federal		22,601,650

To record initial value of estimated petroleum royalties due to change in accounting principle and the liabilities for revenue distributions to non-federal entities. (The 85% expected to be distributed to federal entities increases the net position of the entity responsible for making royalty collections)

Transactions two through ten will be recorded throughout the fiscal year by the component entity responsible for collecting royalties and, in some cases, the receiving federal entity.

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, bonus bid number two was \$1,900, bonus bid number three was \$1,950, and bonus number four was \$2,000. The total payment relating to the four bonus bids was \$1,540 (bonus bid number one for \$370, bonus bid number two for \$380, bonus bid number three for \$390, and bonus bid number four for \$400) and was recorded with the following entry by the component entity responsible for collecting royalties.

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

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 liability for revenue distributions to non-federal entities.

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

- Deleted: others
- Deleted: the states
- Deleted: others
- Deleted: the states
- Deleted: others
- Deleted: 20,000
- Deleted: oun
- Deleted: ing
- Deleted: ¶
- Deleted: Cr Liability for Revenue Distribution to Others-Federal
- Deleted: 200
- Deleted: enue
- Deleted: istribution
- Deleted: States-
- Deleted: 14,000¶
5,800
- Deleted: state and local governments
- Deleted: and other federal component
- Deleted: 1
- Deleted: returned to
- Deleted: increases its net position.
- Formatted: Font: 11 pt
- Deleted: Other federal component entity entry:¶ ... [4]
- Deleted: others

1
2
3
4
5
6
7

8

\$2,000. The remaining four-fifths bonus bid of \$1,600 and the first year rental fee in the amount of \$360 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
 Dr Fund Balance with Treasury
 Cr Revenue from Rent
 Cr Revenue from Bonus Bid

400
 1,960
 360
 2,000

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

- Deleted: 1
- Deleted: ,0
- Deleted: 10,500
- Deleted: 0,00
- Deleted: 9
- Deleted: ,0

The increase in the liability for revenue distributions to non-federal entities is calculated by multiplying the revenue from rent and bonus bid by the average share of the revenue distributed to state governments and other non-federal entities. For this illustration, 15 percent was used as the average annual share of the revenue distributed to state governments and other non-federal entities based on the average distribution for 2005. This calculation is presented below:

$$\underline{\$2,360 \times .15 = \$354}$$

Dr Revenue Designated for Others – Non-Federal³⁰
 Cr Liability for Revenue Distribution to Others – Non-Federal

354
 354

To record the increase in the liability for revenue distributions to non-federal entities.

- Deleted: the states
- Deleted: the states
- Deleted: others

- Deleted: the States
- Deleted: ¶
- Dr Transfers-Out .
- Deleted: 1,725
- Deleted: Cr Liability for Revenue Distribution to Others-Federal¶

4. Receive the annual rental fee from pre-existing leases and record the liability for revenue distributions to non-federal entities.

For illustrative purposes, the total amount of annual rent collected for the year for offshore leases was \$193,274 and the rental fee for onshore leases was \$46,588 for a total of \$239,862. Since \$360 was received in connection with the new lease, the rental payments remaining are \$239,502 (\$239,862 less \$360). The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury
 Cr Revenue from Rent

239,502
 239,502

To record rental payments on leases for the year.

- Deleted: enue
- Deleted: States
- Deleted: -
- Deleted: 9,660¶
- Deleted: the future
- Deleted: others
- Deleted: Other federal component entity entry:¶
- Deleted: others
- Deleted: 1,000
- Deleted: 1,000
- Deleted: the states
- Deleted: others
- Deleted: the states
- Deleted: others

The increase in the liability for the rent revenue to be distributed to non-federal entities is calculated by multiplying the revenue from rent by the average share of the revenue distributed to state governments and other non-federal entities. For this illustration, 15 percent was used as an average annual share of the revenue distributed to state governments and other non-federal entities based on the average distribution for 2005. This calculation is presented below:

³⁰ 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.

1 | $\$239,502 \times .15 = \$35,925$
 2 | Dr Revenue Designated for Others – Non-Federal 35,925
 Cr Liability for Revenue Distribution to Others – Non-Federal 35,925
 3 | To record the increase in the liability for revenue distributions to non-federal entities.

To record the 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 number one in the amount of \$370, bonus bid number two in the amount of \$380, and bonus bid number three in the amount of \$390 for a total of \$1,140 are returned to respective bidders. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Unearned Revenue 1,140
 Cr Fund Balance with Treasury 1,140
 To record refund of losing bonus bids.

6. Record royalty revenue and depletion expense.

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 on or before the last of the month following the month the oil or gas produced 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 for the fiscal year for offshore and onshore rental leases was used in this calculation. The royalty revenue during the fiscal year for offshore leases was \$3,563,922 and the royalty revenue during the fiscal year for onshore leases was \$852,331 for a total of \$4,416,253. The following entries are recorded by the component entity responsible for collecting royalties.

Dr Accounts Receivable 4,416,253
 Cr Revenue from Royalties for Federal Oil and Gas Reserves 4,416,253
 To record royalty revenue.

Dr Oil and Gas Depletion Expense 4,416,253
 Cr Estimated Petroleum Royalties 4,416,253
 To record depletion expense for federal oil and gas resources.

- Deleted: the States
- Deleted: 150
- Deleted: Dr Transfers-out¶
- Deleted: Cr Liability for Revenue Distribution to Others-Federal¶
- Deleted: enue
- Deleted: States
- Deleted: the future
- Deleted: others
- Deleted: Other federal component entity entry:¶ ... [6]
- Deleted: ¶
- The remaining pro-forma transactions and financial statements are presented as of the end of the federal government's fiscal year (FY).¶
- Deleted: earned
- Deleted: Earned r
- Deleted: t
- Deleted: earned
- Deleted: earned
- Deleted: enue
- Deleted: 600
- Deleted: 600
- Deleted: earned
- Deleted: 600
- Deleted: ¶
- Deleted: 600

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 produced 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 \$4,048,232. The following entry is recorded by the component entity responsible for collecting royalties.

Dr Fund Balance with Treasury 4,048,232
 Cr Accounts Receivable 4,048,232

To record collection of royalty revenue.

- Deleted: t
- Inserted: t 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 \$4,048,232. The following entry is recorded by the component entity responsible for collecting royalties.¶
- Deleted: 400
- Deleted: 400
- Deleted: others

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

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, the rent collected was \$239,862 and the royalties collected was \$4,048,232 for total collections of \$4,290,094.

The bonus bid, rent, and royalty revenue collections distributed and the reduction in the liability for revenue distribution to non-federal entities is calculated in two parts. The first part is based on revenue collections designated as payments to non-federal entities while the second 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 state governments and other non-federal entities to obtain the value of the collections to be distributed to non-federal entities. For this illustration, 15 percent was used as an average annual share of the revenue distributed to non-federal entities based on the average distribution for 2005. 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. These calculations are presented below:

$$\begin{aligned} \$4,290,094 \times .15 &= \$643,514 \\ \$4,290,094 \times .84 &= \$3,603,678 \end{aligned}$$

Dr Liability for Revenue Distribution to Others – Non-Federal 643,514
 Dr Transfers-Out 3,603,678
 Cr Fund Balance with Treasury 4,247,192

To record distribution of bonus bid, rent, and royalty revenue collections, the transfer out to other federal component entities, and the reduction in liabilities for revenue distribution to non-federal entities.

- Deleted: related
- Deleted: others
- Deleted: the states
- Deleted: others
- Deleted: Dr Liability for Revenue Distribution to Others-Federal¶
- Deleted: enue
- Deleted: States-
- Deleted: 10,710¶
- Deleted: 1,890
- Deleted: 12,600
- Deleted: others

1

Other federal entity entry:

Dr Fund Balance with Treasury 3,603,678
 Cr Transfer-in 3,603,678
 To increase the fund balance with treasury and recognize a transfer-in for distributions received.

- Deleted: 10,710
- Deleted: Long-Term A/R for Oil and Gas-Federal
- Deleted: 10,710
- Deleted: reduce the long-term accounts receivable for oil and gas in relation to

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 sometime during the next fiscal year.

The estimated value of the future royalty stream identified to be sold from field number one is \$5,305 based on the following calculation: 1,000 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 \$3,245 based on the following calculation: 750 barrels to be sold X \$34.61 per barrel per field number two first purchase price for oil X the 12.5% royalty rate for field number two.

- Deleted: . The future royalty streams are expected to be sold sometime during the next fiscal year
- Deleted: 9
- Deleted: related
- Deleted: others

10. Record sale of future royalty streams identified for sale and the change in the liability for revenue distributions to non-federal entities.

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 based on the following calculation: 1,000 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. As a result, there is a loss of \$1,425 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
 Dr. Loss on Sale of Estimated Petroleum Royalties 1,425
 Cr. Estimated Petroleum Royalties 5,375

Deleted: 750
 Deleted: 150
 Deleted: 900

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 state governments and other non-federal entities to obtain the reduction in the liabilities for revenue distributions to non-federal entities. For this illustration, 15 percent was used as an average annual share of the revenue distributed to state governments and other non-federal entities based on the average distribution for 2005. 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. These calculations are presented below:

Deleted: the states
 Deleted: others
 Deleted: related
 Deleted: the states
 Deleted: others

$\$1,425 \times .15 = \214
 $\$1,425 \times .84 = \$1,197$

Dr Liability for Revenue Distributions to Others – Non-Federal 214
 Cr Revenue Designated for Others – Non-Federal 214

Deleted: Dr Liability for Revenue Distributions to Others- Federal ¶

To record the reduction in the liabilities and revenue designated for non-federal entities as a result of the loss on the sale of estimated petroleum royalties

$\$3,950 \times .15 = \593
 $\$3,950 \times .84 = \$3,318$

Deleted: States-
 Deleted: 127
 Deleted: the States
 Deleted: Cr Transfers-Out

Dr Transfers-Out
 Dr Liability for Revenue Distributions to Others – Non-Federal 3,318
 Cr Fund Balance with Treasury 593
3,911

Deleted: for the future revenue distributions to others
 Deleted: the States,
 Deleted: and transfers-out

To record the distribution of collections from the sale of revenue streams, the transfer out to other federal component entities, and the reduction in the liability for revenue distributions to non-federal entities.

Deleted: 756
 Deleted: Dr Liability for Revenue Distributions to Others- Federal ¶

Other federal entity entry:

Dr. Fund Balance with Treasury 3,318
 Cr. Transfer-in 3,318

Deleted: 756
 Deleted: Long-Term A/R for Oil and Gas-Federal

To increase the fund balance with treasury and recognize a transfer-in for distributions received.

At the end of each fiscal year, the following transaction is recorded by the component entity responsible for collecting royalties.

Deleted: ¶

11. Record annual valuation of estimated petroleum royalties and the change in the liability for revenue distributions to non-federal entities.

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, 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 \$25,210,226 that is based on the following calculations.

The revaluation value of estimated petroleum royalties for oil and gas is hypothetically valued at \$171,466,265. The current value of estimated petroleum royalties (\$171,466,265) 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:

$$\$171,466,265 - (150,677,667 - 4,416,253 - 5,375) = \$25,210,226$$

Dr Estimated Petroleum Royalties 25,210,226
 Cr Gain on Revaluation of Estimated Petroleum Royalties³¹ 25,210,226

- Deleted: 5,000
- Deleted: 5,000

To record revaluation of estimated petroleum royalties.

To record the increase in the liability for the revenue distributions to non-federal entities, the amount that the total estimated petroleum royalties was increased due to revaluation is multiplied by the average share of the revenue distributed to state governments and other non-federal entities. For this illustration, 15 percent was used as an average annual share of the revenue distributed to state governments and other non-federal entities based on the average distribution for 2005.³² This calculation is presented below:

$$\$25,210,226 \times .15 = \$3,781,534$$

Dr Revenue Designated for Others – Non-Federal 3,781,534
 Cr Liability for Revenue Distributions to Others – Non-Federal 3,781,534

- Deleted: the states
- Deleted: the states
- Deleted: the States
- Deleted: 750
- Deleted: Dr Transfers-Out¶
- Deleted: Cr Liability for Revenue Distributions to Others-Federal ¶
- Deleted: States-
- Deleted: 4,250¶
750¶
- Deleted: future
- Deleted: others
- Deleted: Other federal component entity entry:¶
- Deleted: entries

To record the year-end increase in the liabilities for the revenue distributions to non-federal entities.

1
 2 The pro forma financial statements that follow are illustrative of the departmental entries
 3 presented in this appendix. The “other federal component entity” [financial statements](#) and the
 4 consolidated financial statements of the United States Government are not illustrated.

³¹ This gain will be illustrated on the statement of net cost as partially due to changes in assumptions. This display is further illustrated in SFFAS 33.

³² See footnote 40.

[This page intentionally left blank.]

1 | The following pro forma financial statements are illustrative of the presentation of basic
 2 | information. Until such time that the information is presented as basic, information
 3 | reported as RSI would be presented as part of a schedule of estimated petroleum
 4 | royalties and not reported in the principal financial statements.

Comment: From W. Jackson:
 Distinguish between presentation for
 RSI information and basic
 information.

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

Balance Sheet

Assets

Fund Balance with Treasury	\$ 42,941
Accounts Receivable	368,021
Estimated Petroleum Royalties	<u>171,466,265</u>
Total Assets	\$ <u>171,877,227</u>

Deleted: 159
 Deleted: 200
 Deleted: 23,500
 Deleted: 23,859

Liabilities

Liability for Revenue Distributions to <u>Others – Non-Federal</u>	<u>25,775,142</u>
Total Liabilities	<u>25,775,142</u>

Deleted: Liability for Revenue
 Distributions to Others-Federal¶

Net Position

Cumulative Results of Operations	<u>146,102,085</u>
Total Liabilities and Net Position	\$ <u>171,877,227</u>

Deleted: States
 Deleted: -
 Deleted: 17,167¶
 6,377
 Deleted: 23,544
 Deleted: 315
 Deleted: 23,859

Statement of Net Cost

Oil and Gas Resources Program

Leasing Activities:	
Costs (Oil and Gas Depletion Expense)	\$ 4,416,253
Less: Revenue	<u>(4,658,115)</u>
Net Cost/(Revenue) from Leasing Operations	<u>(241,862)</u>
Loss/(Gain) on Revaluation of Estimated Petroleum Royalties	<u>(25,010,226)</u>
Less: Revenue Designated for <u>Others – Non-Federal</u>	<u>3,817,599</u>
Less: Loss on Sale of Future Royalty Rights	<u>1,425</u>
Net Cost/(Revenue) for Program before (gain)/loss from changes in assumptions	\$ <u>(21,433,064)</u>

Deleted: 600
 Deleted: Earned
 Deleted: 13,100
 Deleted: 12,500
 Deleted: 3,000
 Deleted: the States
 Deleted: 2,602
 Deleted: 150
 Deleted: 12,748

1 **Appendix D: Abbreviations**

2	Bbl	Barrels
3	CFR	Consolidated Financial Report
4	CFR	Code of Federal Regulations
5	DOI	Department of Interior
6	ED	Exposure Draft
7	EIA	Energy Information Administration
8	FASAB	Federal Accounting Standards Advisory Board
9	FASB	Financial Accounting Standards Board
10	GAAP	Generally Accepted Accounting Principles
11	Mcf	Thousand Cubic Feet
12	MMS	Minerals Management Service
13	OCS	Outer Continental Shelf
14	NGPLs	Natural Gas Plant Liquids
15	RSI	Required Supplementary Information
16	SEC	Securities and Exchange Commission
17	SFAC	Statement of Financial Accounting Concepts
18	SFFAC	Statement of Federal Financial Accounting Concepts
19	SFAS	Statement of Financial Accounting Standards
20	SFFAS	Statement of Federal Financial Accounting Standards
21	U.S.	United States
22	USGS	U.S. Geological Survey

Deleted: API . American Petroleum Industry

Deleted: BLM . Bureau of Land Management

[This page intentionally left blank.]

1 **Appendix E: Glossary**

2 -----

3

4

Definitions of Resource and Reserve Components and Subcomponents

5

6

7 Provided below are definitions used by federal entities to describe oil and gas resource and
8 reserve components and subcomponents. The source of these definitions is OCS Report MMS
9 2003-050 unless otherwise noted.

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

15

16

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

23

24

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

26

27

Undiscovered Resources

28

29

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

34

- Undiscovered Non-Recoverable Resources

35

36

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

Comment: From H. Steinberg

Deleted: is

39

- Undiscovered Recoverable Resources

40

41

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

- 1
2 1. Undiscovered, conventionally recoverable resources: The portion of the hydrocarbon
3 potential that is producible, using present or reasonably foreseeable technology, without
4 any consideration of economic feasibility.
- 5 2. Undiscovered, economically recoverable resources: The portion of the undiscovered
6 conventionally recoverable resources that is economically recoverable under imposed
7 economic scenarios.

8 9 **Discovered Resources**

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

14
15 Identified resources are resources whose location and quantity are known or are estimated from
16 specific geologic or engineering evidence and include economic, marginally economic, and
17 subeconomic components.

18 19 **Reserves**

20 In accordance with the Society of Petroleum Engineers (SPE), the World Petroleum Congresses
21 (WPC), and the American Association of Petroleum Geologists (AAPG), the definition for
22 “reserves” and the following explanatory paragraphs are presented as follows³³:

23
24 “Reserves are those quantities of petroleum which are anticipated to be commercially
25 recovered from known accumulations from a given date forward. All reserve estimates
26 involve some degree of uncertainty. The uncertainty depends chiefly on the amount of
27 reliable geologic and engineering data available at the time of the estimate and the
28 interpretation of these data.”

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

31 32 **Unproved Reserves**

33
34 After a lease qualifies under 30 CFR 250.11, the MMS Field Naming Committee reviews the
35 new producible lease to assign it to an existing field or, if the lease is not associated with an
36 established geologic structure, to a new field. Regardless of where the lease is assigned, the
37 reserves associated with the lease are initially considered to be unproved reserves. Unproved
38 reserves are based on geologic or engineering information similar to that used in estimates of
39 proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such
40 reserves from being classified as proved.

41
42 Unproved reserves may be divided into two subclassifications, possible and probable,
43 which are similarly based on the level of uncertainty.

³³ WPC/SPE/AAPG Petroleum Reserves and Resources Definitions.

1
2 "Unproved possible reserves are less certain than unproved probable reserves and can
3 be estimated with a low degree of certainty, which is insufficient to indicate whether they
4 are more likely to be recovered than not. Reservoir characteristics are such that a
5 reasonable doubt exists that the project will be commercial" (SPE, 1987). After a lease
6 qualifies under 30 CFR 250.11, the reserves associated with the lease are initially
7 classified as unproved possible.

8
9 "Unproved probable reserves are less certain than proved reserves and can be
10 estimated with a degree of certainty sufficient to indicate they are more likely to be
11 recovered than not" (SPE, 1987). Reserves in fields for which a schedule leading to a
12 Development and Production Plan (DPP) has been submitted to the MMS have been
13 classified as unproved probable.

14 **Proved Reserves**

15
16
17 "Proved reserves can be estimated with reasonable certainty to be recoverable under
18 current economic conditions, such as prices and costs prevailing at the time of the
19 estimate. Proved reserves must either have facilities that are operational at the time of the
20 estimate to process and transport those reserves to market or a commitment or
21 reasonable expectation to install such facilities in the future" (SPE, 1987). Proved
22 reserves can be subdivided into undeveloped and developed.

23
24 "Proved undeveloped reserves are classified proved undeveloped when a relatively
25 large expenditure is required to install production and/or transportation facilities, a
26 commitment by the operator is made, and a timeframe to begin production is
27 established. Proved undeveloped reserves are reserves expected to be recovered from
28 (1) yet undrilled wells, (2) deepening existing wells, or (3) existing wells for which a
29 relatively large expenditure is required for recompletion.

30
31 "Proved developed reserves are classified as proved developed when the reserves are
32 expected to be recovered from existing wells (including reserves behind pipe). Reserves
33 are considered developed only after necessary production and transportation equipment
34 have been installed or when the installation costs are relatively minor. Proved developed
35 reserves are subcategorized as producing or non-producing" (SPE, 1987). This
36 distinction is made at the reservoir level and not at the field level.

- 37
38
- 39 • Any developed reservoir in a developed field that has not produced or has not had
40 sustained production during the past year is considered to contain proved developed
41 non-producing reserves. This category includes reserves contained in non-producing
42 reservoirs, contained reserves behind-pipe, and reservoirs awaiting well workovers or
43 transportation facilities.
 - 44 • Once the first reservoir in a field begins production, the reservoir is considered to
45 contain proved developed producing reserves, and the field is considered on
46 production. If a reservoir had sustained production during the last year, it is considered
47 to contain proved developed producing reserves.

Production represents the proved oil and gas reserves that were extracted from existing reserves.³⁴

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

Other Definitions

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.

Basin: The site of accumulation of a large thickness of sediments.³⁵

Bonus Bid: Leases issued in areas known to contain minerals are awarded through a competitive bidding process. A bonus bid, as used in this Statement, represents the cash amount successfully bid to win the rights to a lease.³⁶

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.

Crude 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.

³⁴ Adapted from Gas Energy Review, Gas Supply and Demand Committee, July 1995, Vol.23 No. 7.

³⁵ U.S. Geological Survey, Geologic Glossary.

³⁶ Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior. ([Glossary of Mineral Terms](#))

Deleted: -----¶
-----¶
¶ **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.¶
¶ **Estimated Production:** The volumes of oil and gas that are extracted or withdrawn from reservoirs during the report year. ¶
¶ **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.¶

... [8]

Deleted: standard

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

5
6 **Estimated petroleum royalties** means the estimated end-of-period value of the federal
7 government's royalty share of proved oil and gas reserves from federal oil and gas resources.

8
9 **Estimated Production:** The volumes of oil and gas that are extracted or withdrawn from
10 reservoirs during the report year.

11
12 **Estimated Value for Royalty Relief:** Existing statutes authorize the Minerals Management
13 Service (MMS) to grant royalty relief to operators on the production of oil and gas resources
14 from federal oil and gas leases. Royalty relief is the reduction, modification, or elimination of
15 any royalty to operators to promote development, increase production, or encourage production
16 of marginal resources on certain leases or categories of leases. The estimated value for royalty
17 relief is the calculated approximation of royalty relief based on a formula developed by the
18 Department of the Interior.

19
20 **Extensions:** The reserves credited to a reservoir because of enlargement of its proved area.
21 Normally the ultimate size of newly discovered fields, or newly discovered reservoirs in old
22 fields, is determined by wells drilled in years subsequent to discovery. When such wells add to
23 the proved area of a previously discovered reservoir, the increase in proved reserves is
24 classified as an extension.

25
26 **Federal Oil and Gas Resources:** Oil and gas resources over which the federal government
27 may exercise sovereign rights with respect to exploration and exploitation and from which the
28 federal government has the authority to derive revenues for its use. Federal oil and gas
29 resources do not include resources over which the federal government acts as a fiduciary for
30 the benefit of a non-federal party.

31
32 **Federal jurisdiction** is defined under accepted principles of international law. The seaward limit
33 is defined as the farthest of 200 nautical miles seaward of the baseline from which the breadth
34 of the territorial sea is measured or, if the continental shelf can be shown to exceed 200 nautical
35 miles, a distance not greater than a line 100 nautical miles from the 2,500-meter isobath or a
36 line 350 nautical miles from the baseline.

37
38 **Field** is an area consisting of a single reservoir or multiple reservoirs all grouped on, or related
39 to, the same individual geological structural feature and/or stratigraphic condition. There may be
40 two or more reservoirs in a field that are separated vertically by intervening impervious strata or
41 laterally by local geologic barriers, or by both. The area may include one lease, a portion of a
42 lease, or a group of leases with one or more wells that have been approved as producible.

43
44 **First purchase price** is the actual amount paid by the first purchaser for crude oil as it leaves
45 the lease on which it was produced.³⁷ A "first purchase" constitutes a transfer of ownership of

³⁷ EIA-182 Domestic Crude Oil First Purchase Report Instructions.

1 crude oil during or immediately after the physical removal of the crude oil from a production
2 property for the first time.

3
4 **Gas:** A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons
5 existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at
6 reservoir conditions.

7
8 **Hydrocarbon:** An organic chemical compound of hydrogen and carbon in the gaseous, liquid,
9 or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest
10 (methane, a constituent of natural gas) to the very heavy and very complex.

11
12 **Lease:** "Lease," as used in this [Statement](#), means any contract, profit-share arrangement, joint
13 venture, or other agreement issued or approved by the United States under a mineral leasing
14 law that authorizes exploration for, extraction of, and/or removal of oil or gas.³⁸

15
16 **Lease condensate:** A mixture consisting primarily of pentanes and heavier hydrocarbons which
17 is recovered as a liquid from natural gas in lease separation facilities. This category excludes
18 natural gas plant liquids, such as butane and propane, which are recovered at downstream
19 natural gas processing plants or facilities.

20
21 **Long-term Assumptions:** Assumptions are considered long-term if the underlying event about
22 which the assumption is made will not occur for five years or more. If the event is one of a series
23 of events the entire series should be considered the event and, thus, the payment may
24 commence within one year but would be required to extend at least five years. Otherwise, the
25 asset or liability would be classified as short-term.

26
27 **Marketable Treasury Securities:** Debt securities, including Treasury bills, notes, and bonds,
28 that the U.S. Treasury offers to the public and are traded in the marketplace. Their bid and ask
29 prices are quoted on securities exchange markets.

30
31 **Natural gas plant liquids (NGPLs):** Those hydrocarbons in natural gas that are separated as
32 liquids at natural gas processing plants, fractionating and cycling plants, and, in some instances,
33 field facilities. Lease condensate is excluded. Products obtained include ethane; liquefied
34 petroleum gases (propane, butanes, propane-butane mixtures, ethane-propane mixtures);
35 isopentane; and other small quantities of finished products, such as motor gasoline, special
36 naphthas, jet fuel, kerosene, and distillate fuel oil.

37
38 **Net of Sales and Acquisitions:** the net change in the quantity of reserve estimates, either
39 positive or negative, as a result of reserves gained through purchase and deducted through sale
40 during the report year.

41
42 **New Field Discoveries:** The volumes of proved reserves of crude oil, natural gas and/or
43 natural gas liquids discovered in new fields during the report year.

44

Deleted: 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.¶

Deleted: standard

³⁸ 30 U.S.C. §1702 (5).

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.

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.

Outer Continental Shelf (OCS): 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**.³⁹

Play: A group of **pools** that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment.⁴⁰

Pool: A discovered or undiscovered accumulation of hydrocarbons, typically within a single stratigraphic interval.⁴¹

Present Value: The value of future cash flows discounted to the present at a certain interest rate (such as the reporting entity's cost of capital), assuming compound interest.

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.

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 gas reserves from federal oil and gas resources in each region.

Rent: Rent, as used in this Statement, 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. A rent schedule is established at the time a lease is issued.⁴²

Deleted: standard

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.⁴³

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

Deleted: , Minerals Revenue Management, Mineral Management Service, U.S. Department of the Interior.

Deleted: Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior.

Deleted: Glossary of Mineral Terms, Minerals Revenue Management, Minerals Management Service, U.S. Department of the Interior

³⁹ Glossary of Mineral Terms.

⁴⁰ Ibid.

⁴¹ Ibid.

⁴² Ibid.

⁴³ Ibid.

1 errors and adjustments to prior year-end production volumes to the extent that these alter
2 reported prior year reserves estimates.

3
4 **Revisions and Adjustments:** the net change in the quantity of reserve estimates, either
5 positive or negative, as a result of adding changes reported as revisions and adjustments during
6 the report year.

7
8 **Royalty:** Royalty, as used in this Statement, means any payment based on the value or
9 volume of production which is due to the United States on production of oil or gas from the
10 Outer Continental Shelf or federal lands, or any minimum royalty owed to the United States
11 under any provision of a lease.⁴⁴

Deleted: standard

12
13 **Royalty-in-kind:** A program operated under the provisions of the Mineral Leasing Act of 1920
14 and the Outer Continental Shelf Lands Act of 1953. The federal government, as lessor, may
15 take part or all of its oil and gas royalties "in kind" (a volume of the commodity) as opposed to "in
16 value" (money). Under the oil royalty-in-kind program, the government sells oil at fair market
17 value to eligible refiners who do not have access to an adequate supply of crude oil at equitable
18 prices. The Minerals Management Service conducted a gas royalty-in-kind pilot program in
19 1995, entering into contracts to sell selected Gulf of Mexico natural gas by competitive bid to
20 gas marketers. Two additional oil and gas pilot programs began in 1998, and a third gas pilot
21 program began in 1999.⁴⁵

22
23 **Royalty rate:** A proportionate interest in the production value of mineral deposits due the
24 lessor from the lessee in accordance with a lease agreement.

25
26 **Sales:** The volume of proved reserves deducted from an operator's total reserves when selling
27 an existing field or property, during the calendar year.

28
29 **Sales Value:** The proceeds received for the sale of a product. Sales value is calculated by
30 multiplying the sales volume by unit price.

31
32 **Sales Volume:** The volume, or quantity, of the product that is sold. The sales volume is
33 measured in thousand cubic feet (mcf) for gas and in barrels (bbl) for oil.

34
35 **States' jurisdiction** is defined as follows:

- 36 • Texas and the Gulf coast of Florida are extended 3 marine leagues (9 nautical miles)
37 seaward from the baseline from which the breadth of the territorial sea is measured.
- 38 • Louisiana is extended 3 imperial nautical miles (imperial nautical mile = 6080.2 feet)
39 seaward of the baseline from which the breadth of the territorial sea is measured.
- 40 • All other States' seaward limits are extended 3 nautical miles (approximately 3.3 statute
41 miles) seaward of the baseline from which the breadth of the territorial sea is measured.
42

⁴⁴ Adapted from 30 U.S.C. § 1702 (14).

⁴⁵ [Glossary of Mineral Terms.](#)

1 | **Technically recoverable resources:** For purposes of this Statement, the term used to describe
2 | the total quantity of undiscovered recoverable resources and unproved reserves. Proved
3 | reserves are not included in the estimated quantity of technically recoverable resources.

Deleted: standard

4 |
5 | **Total Discoveries:** the total quantity of additional discovered reserves which is calculated by
6 | adding the quantity of reserves reported as a result of extensions, the quantity of reserves
7 | reported as a result of new field discoveries, and the quantity of reserves reported as a result of
8 | new discoveries in old fields during the report year.

9 |
10 | **Wellhead price** is the value of the purchased natural gas at the mouth of the well. In general,
11 | the wellhead price is considered to be the sales price obtainable from a third party in an arm's
12 | length transaction. Posted prices, requested prices, or prices as defined by lease agreements,
13 | contracts, or tax regulations should be used where applicable.⁴⁶

⁴⁶ Energy Information Administration Glossary, http://www.eia.doe.gov/glossary/glossary_w.htm.

FASAB Board Members

Tom L. Allen, Chair
Robert F. Dacey
John A. Farrell
Norwood J. Jackson, Jr.
James M. Patton
Robert N. Reid
Alan H. Schumacher
Harold I. Steinberg
Danny Werfel

FASAB Staff

Wendy M. Payne, Executive Director

Project Staff

Julia Ranagan

Federal Accounting Standards Advisory Board
441 G Street NW, Suite 6814
Mail Stop 6K17V
Washington, DC 20548
Telephone 202-512-7350
FAX 202-512-7366
www.fasab.gov

Regional Average First Purchase Price for Oil: The regional average first purchase price for oil is calculated by dividing the total regional sales value of oil 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 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.

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

Effective Regional Average Royalty Rate: The effective regional average royalty rate is calculated by dividing the royalty value (royalties) earned on the oil and gas proved 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.

A narrative describing and a display showing the following historical information about proved oil 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; new reservoir 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."

and a corresponding transfer in.

Other federal component entity entry:

Dr Long-Term A/R for Oil and Gas-Federal	14,000	
Cr Prior Period Adjustment: Change in Accounting Principle		14,000

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

Other federal component entity entry:

Dr Long-Term A/R for Gas and Oil-Federal	9,660	
Cr Transfer-In		9,660

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

Page 47: [6] Deleted **GAO** **2/12/2009 11:36 AM**

Other federal component entity entry:

Dr Long-Term A/R for Gas and Oil-Federal	850	
Cr Transfer-In		850

Page 51: [7] Deleted **GAO** **2/4/2009 8:07 AM**

Other federal component entity entry:

Dr Long-Term A/R for Oil and Gas-Federal	4,250	
Cr Transfers-In		4,250

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

Page 60: [8] Deleted **GAO** **2/10/2009 10:42 AM**

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.

Estimated Production: The volumes of oil and gas that are extracted or withdrawn from reservoirs during the report year.

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.

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 new discoveries in old fields during the report year.

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

Natural Resources

History of Project and Key Decisions

May 1995 - Present

July 1995 - Staff presented first issue paper; Board requested more background information, including a review of relevant FASB standards.

November 1995 - SFFAS 6, *Accounting for Property, Plant, and Equipment* issued; only addressed surface land area, excludes natural resources due to complex issues involved.

April 1996 - The Board determined that stocks of game, fisheries, and wildlife habitat would be excluded from the scope of the standard. Also, Board decided it is only interested in reporting information about natural resources contained on federal lands. Staff was directed to prepare a hierarchy of disclosure standards for all traditional natural resources, excluding timber. Staff was directed to prepare separate requirements for timber.

May 1996 (contd.) - Staff presented the Board with possible reporting requirements for a natural resources standard and proposed four categories of natural resources: (1) natural resources extracted, produced, and sold by a federal entity; (2) quantifiable lease program natural resources; (3) non-quantifiable lease program natural resources; and (4) timber. Concerned with relevance and reliability, the Board decided to create a task force to study the kinds of natural resources information currently available and to provide options for framing relevant information to be reported in federal financial reports.

January 1997 - Natural resources task force held its first meeting. The task force was made up of accountants, economists, geologists, and program experts from various federal entities and the private sector.

October 1997 - Mr. Leshner presented the Board with an update of the task force activities since January 1997, including natural resources addressed and the current view of natural resource "stages" (stocks and flows): conveyed/sold; available for sale; not available for sale; and unknown/undiscovered resources. The specific natural resources addressed within the scope of the project are: timber; outer continental shelf oil and gas resources; leasable minerals (e.g., oil, gas, coal, oil shale, geothermal resources, gilsonite, phosphate, potassium, potash, sodium); locatable minerals (e.g., gold, silver, nickel); mineral materials (e.g., sand, stone, gravel, pumice, and other volcanic stone, clay and rock); grazing rights; electromagnetic spectrum; and water rights. Mr. Leshner said the task force expected to have preliminary recommendations by December.

May 1995 - Natural resources identified as a high priority project. Former executive director (Ron Young) announced that staff would begin developing an issue paper.

September 1995 - Staff provided Board members with an informational paper on FASB SFAS 19, 25, 69 and 89.

January 1996 - Staff provided Board members with a paper that listed federal agencies and their responsibilities for natural resources; an updated set of issues; and, the type of information on natural resources currently available.

May 1996 - SFFAS 7, *Accounting for Revenue and Other Financing Sources* issued; excluded royalty revenue from SoNC even though exchange because there is no offsetting depletion expense. This remains an exception to the recognition of exchange revenue on the SoNC (along with the auction of the radio spectrum).

June 1996 - SFFAS 8, *Supplementary Stewardship Reporting*, issued; only addressed surface land area, excluded natural resources from stewardship reporting due to complex issues involved.

September 1996 - Board approved formation of natural resources task force and related "Charge to Task Force" memorandum, noting that reporting a source of the country's wealth and its potential wealth for the future was important. Schuyler Leshner appointed as chair of task force. Executive Director Ron Young retired September 30, 1996.

April 1997 - The task force chair presented revised scope of task force charge, stating that the project would include those extractable natural resources owned by the federal government or under federal stewardship and the electromagnetic spectrum, where a commercial market exists for the resource. This includes economic mineral resources (e.g., oil, gas, coal, gold, silver, sand, clay, gravel, etc) and the following renewable resources: timber, forage, and water for which the federal government owns the rights.

January 1998 - The task force chair presented a preliminary draft of a natural resources fact-finding paper. While the outline of the paper identified nine major sections, the paper addressed only three of the sections. Mr. Leshner said the task force expected to complete work on the remaining sections of the fact-finding paper in about 6 weeks.

Natural Resources

History of Project and Key Decisions

May 1995 - Present

April 1998 - Task force presented a revised paper that included a discussion on the general reporting principles, including asset reporting, accounting and reporting for revenue, and accounting and reporting for costs. The revised paper also contained a section on the impact of the proposed changes on current FASAB standards and a discussion on Indian natural resource assets held by the federal government in trust for Indian tribes and individuals.

March 1999 - Natural Resources Task Force Draft Report issued from Mr. Leshner to the CFO Council and PCIE Members for comment. Comments were requested by May 3, 1999.

December 2000 - The Board voted to eliminate the category RSSI - required supplementary stewardship information.

[Project deferred to address other issues]

October 2002 - After reviewing and discussing a revised project plan presented by staff, the Board approves work to commence on the current natural resources project.

February 2003 - Staff presented a revised project plan that included the integration of possible revisions to the current FASAB reporting objectives. The Board directed staff to begin developing an ED with a BfC.

June 2003 - The Board asked staff to look at how the proposed recognition of oil and gas resource collections and disbursements would affect an entity's Statement of Custodial Activities and prepare pro forma disclosures that could be included in entity financial reports. Staff was also asked to research the pros and cons for capitalizing oil and gas assessments (an assessment is an estimate of undiscovered oil and gas resources on the basis of geologic knowledge and theory to exist outside of known accumulations).

December 2003 - Staff informed the Board that MMS does not track assessment costs separately from other resource evaluation (RE) costs. In addition, total RE costs are immaterial in comparison to annual bonus bid, rent, and royalty collections. Staff sought approval of proposed oil and gas disclosures with no asset recognition due to the various uncertainties involved in measur-

October 1998 - FASAB staff continued to work with the task force to issue a final task force report. Several more meetings were held to discuss open issues such as whether natural resource exchange revenue that is collected without incurring matching costs should be reported in the Statement of Net Cost or as custodial revenue.

June 2000 - FASAB issues Discussion Paper "*Accounting for the Natural Resources of the Federal Government*" prepared by the FASAB Natural Resources Task Force. The report recommended stewardship reporting as the primary mechanism for reporting information on natural resources. Although the task force believed that the value of natural resources available for sale was important, it concluded that the balance sheet was not the most reliable or effective way to accomplish such reporting due to uncertainty over quantity and market price. Minority comments included in Appendix B of the report state that "resources used for remunerative purposes should be reported on the balance sheet and Statement of Net Cost." The full report is available at <http://www.fasab.gov/pdffiles/natresrpt.pdf>

December 2002 - Staff presented a revised project plan based on prior Board discussions. Staff also provided summarized comments received from several members since the October meeting, noting that these comments leaned toward recognition of natural resources as an asset. The Board agreed that staff would develop standards for oil and gas first and then apply the framework to other types of natural resources.

April 2003 - Staff provided a draft skeletal exposure draft and concluded that, although oil and gas meet FASAB's working definition of "asset," the resources do not meet the recognition criteria because they cannot be reliably measured. The board asked staff to continue their research on current reporting practices as well as options for measuring the oil and gas resources and come back to the Board for discussion.

October 2003 - Staff presented revised proposed disclosure requirements for Board review. The Board directed staff to remove disclosure requirements for total number of leases and non-producing leases and reasons leases are non-producing, concluding that the information was not useful. Staff was also asked to obtain assessment cost information from MMS and provide it to the Board.

Natural Resources

History of Project and Key Decisions

May 1995 - Present

ability. The Board directed staff to pursue capitalization of the anticipated production stage revenue stream, which included researching accounting literature that deals with long-term contracting and leasing in relation to measurement and recognition criteria. This was the Board direction even though staff had initially concluded that quantities from expected oil and gas production were not estimable, due to the unpredictability of the economy, business decisions by the producers, and the advancement, or lack of it, in technology.

July 2004 - Staff presented a proposed valuation methodology and financial statement disclosures using current market value. The Board requested an expanded discussion on alternative measurement attributes. In addition, the Board requested that guidance be sought from the auditors to identify any potential barriers to auditing proved reserves.

December 2004 - Staff presented a revised BfC that included a discussion on many of the questions raised by members at the August 2004 meeting. Members requested additional research and explanation in a number of areas, including a detailed description of "average wellhead price," reliability of EIA proved oil and gas reserve quantities, accounting entries, disclosures, pros and cons of using the discounted cash flow methodology, average time over which oil and gas is extracted from a producing well, and whether bonus bids are proportionate to the value of the federal government's royalty share.

March 2005 - Staff presented another revised BfC to the Board members in which staff had proposed using the national average wellhead price. The Board asked staff to research whether it would be better to use the average wellhead price for each field. The Board also asked staff to perform more research on whether the amount should be discounted. All members, excepts Messrs. Reid and Farrell agreed that information on undiscovered resources should be reported as RSI. Board members decided that the term "estimated Federal royalty share" should be changed to "estimated petroleum royalties."

October 2005 - Staff provided a paper that described the valuation of the federal asset "estimated petroleum royalties" that was based on national average prices and royalty rates. The Board agreed with the staff proposed formulas except Mr. Torregrosa indicated that regional average prices and royalty rates should be used, especially for future revenue streams that had been identified for sale. Board members agreed that a requirement should be added in the standards to address royalty streams identified for sale.

March 2004 - Staff explained that previously, the EIA did not distinguish between the quantity of proved reserves from lands under federal jurisdiction and the quantity of proved reserves from other lands. However, the EIA was then tasked with the requirement to provide this information in its September 2004 reports. Therefore, because this information would be available, staff proposed that an estimated value for proved oil and gas reserves from lands under federal jurisdiction might be capitalized. The Board received information on measurability of proved reserves from MMS and EIA experts via a conference call. The Board agreed that staff should explore the possibility of capitalizing a value for proved oil and gas reserves and consider disclosing information about other classifications of oil and gas resources.

August 2004 - Staff presented a draft ED that proposed using current market value. The ED explained that net present value was eliminated from consideration as a measurement attribute because the period of time over which the money could be earned is not determinable, thereby inhibiting selection of an appropriate discount rate. The Board decided to use the average wellhead price to value cash inflows from oil and gas resources instead of current market value because the wellhead price is what the royalty payment is based on. The wellhead price, which is calculated by EIA, is the value for oil and gas at the mouth of the well and is considered to be the sales price to the initial purchaser without the addition of any other costs, such as transportation and insurance. The Board also decided to change the title of the proposed standards from "Reporting Requirements for Federal Oil and Gas Resources" to "Accounting for Federal Oil and Gas Resources." Staff provided members with a copy of the "Society of Petroleum Engineers (SPE) Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information."

August 2005 - Staff provided EIA and DOI responses to a number of open questions from the March meeting. In addition, a representative from EIA and a representative from DOI attended the meeting and responded to various member questions. The representatives recommended that the calculation for valuing the estimated petroleum royalties be straightforward and manageable. Staff was directed to continue developing the ED.

January 2006 - Staff presented a draft ED that included estimated quantity, price, and royalty rate information on a regional basis rather than at a national level. This was deemed to provide a more representative valuation. Staff also addressed future royalty rights held for sale in the revised ED. The Board

Natural Resources

History of Project and Key Decisions

May 1995 - Present

March 2006 - The Board reviewed a revised draft ED and provided comments, including requesting that staff draft several questions for respondents that cover the level of information requested to be disclosed in the footnotes or displayed as RSI; the challenges posed by the use of the present value measurement attribute for measuring estimated petroleum royalties; and the use of reserves classified as proved, probable, and possible to calculate the value of the federal government's estimated petroleum royalties for capitalization on the balance sheet, instead of using only the proved reserves as proposed in the ED. The Board also requested that staff research the royalty relief program and provide additional information at the next meeting.

July 2006 - The Board reviewed a revised draft ED that included an alternative view from CBO that fair value should be used to value the federal government's natural resources instead of the proposed valuation methodology. There were no objections from Board members to include the CBO alternative view in the ED. The Board also decided to calculate the value of natural gas plant liquids (NGPL) separately from oil and lease condensate. This was the result of an issue raised by CBO that the average price per barrel of NGPL was significantly lower than the average price per barrel of oil and lease condensate. Board members also agreed with CBO's recommendation that the dry (processed) gas price would be used in calculating the value of estimated petroleum royalties for gas as opposed to the wet (unprocessed) gas price. This issue was raised because the proposed standards specified that proved reserves of natural gas would be measured as pipeline quality. The dry (processed) gas is the pipeline-quality gas that has had the liquids removed.

March 2007 - Staff presented the Board with a ballot ED; however, several more clarifying changes were requested to be made to the draft, including that a question on cost/benefit considerations be included in the Request for Comments and a more robust discussion about the current and proposed asset and liability definitions be added. The Board asked staff to make the changes discussed and circulate another pre-ballot draft.

September 2007 - Since the Board received a request for the comment period to be extended and only one comment letter had been received, the Board agreed to extend the comment period until January 11, 2008. Staff was asked to make a concerted effort to reach out to groups and experts to respond.

provided a number of comments on the revised ED, including a request that pro forma accounting transactions, pro forma financial statements, and a discussion of the timing of the transactions be included.

May 2006 - The Board reviewed a revised draft ED and an issue paper on the royalty-free production of oil and gas. Board members agreed that a requirement would be added in the ED to report the annual estimated value for royalty relief as RSI. In addition, they agreed that a question would be added to the request for comments section of the ED pertaining to this requirement. Board members also agreed to staff's recommendation that RSI reporting be required for technically recoverable resources as a whole versus delineating between unproved and undiscovered resources as that information was not readily available. Staff suggested that it begin working on coal for the next phase of the natural resources project. However, the Board directed staff to look at a group of mining materials to try to come up with a standard which has similar principles for a group of mining materials.

November 2006 - The Board asked staff to insert a question addressing the regional disclosure information in the Request for Comments section and to add text in the BfC addressing concerns regarding the proposed disclosures. The Board also tentatively agreed that a liability exists and should be recognized for the estimated petroleum royalties which the government is obligated to distribute to others in accordance with authoritative laws and regulations.

January 2007 - The Board reviewed the revisions to the ED that incorporate the recognition of a liability and clarify the questions for respondents and approved the circulation of a pre-ballot draft prior to the next meeting.

May 2007 - An exposure draft entitled *Accounting for Federal Oil and Gas Resources* was issued for public comment on May 21, 2007. Comments on the proposals presented in the ED were requested by September 21, 2007. The Board requested that the proposal be field tested during the comment period.

February 2008 - Eight comment letters were received through February 4, 2008. Based on the nature of the responses, the Board concluded that a public hearing was not necessary but may elect to follow up on the individual responses as needed. Long-time FASAB project manager Rick Wasca retired.

Natural Resources

History of Project and Key Decisions

May 1995 - Present

June 2008 - The board rejected staff's proposal to develop a comprehensive standard on all natural resources and directed staff to continue with the development of a final standard on oil and gas. Staff will invite DOI to appear before the board to discuss their alternative proposal from the fieldwork testing including why they requested an even lower level of detail than was prescribed in the standard as well as their thoughts on what a less prescriptive standard would mean to them and how it might apply to other resources under their domain. In addition, staff will research the reason the board decided to look at one resource at a time, review current SEC requirements, find out how the private sector currently reports private reserves, obtain revenue numbers on the different types of natural resources, and attempt to make contact with EIA to find out if and when another report on proved reserves under federal lands will be published.

February 2009 - Due to the board's primary focus on long-term projections and social insurance, the natural resources project was not discussed at the February meeting.

October 2008 - After hearing from the DOI representatives regarding their experience during field testing of the May 2007 ED, the board members directed staff to draft a principles-based ED for their consideration.

December 2008 - The board members unanimously supported continuing efforts to issue an ED. The members directed staff to retain the scope of the ED as oil and gas only, preserve the level of detail in the draft ED, delete the formula in the previously exposed ED (quantity X price X royalty rate), and keep the effective date as drafted (three year phase-in from RSI to basic with a date certain). Staff will incorporate those changes and address additional issues (fiduciary reporting, liability classification, component entity RSI, reporting for other commodities, showing gains and losses on the component entity SoNC, and reporting changes in assumptions) while working towards a pre-ballot revised ED for the April 2009 meeting.