



October 8, 2008

Memorandum

To: Members of the Board

From: Julia E. Ranagan, Assistant Director

Through: Wendy M. Payne, Executive Director

Subj: Natural Resources – Tab F¹

MEETING OBJECTIVE

The objective for the October meeting is to hear from the Department of Interior (DOI) representatives regarding their response to the May 2007 exposure draft on *Accounting for Oil and Gas Resources* and related field test questionnaires. To facilitate the discussion, staff provided DOI with a detailed list of questions that the board had raised at the June board meeting (see Tab F-1). Please be prepared with any additional questions that you may have for the DOI representatives while they are present.

BRIEFING MATERIAL

Attached to this transmittal memorandum, you will find the status of four tasks that evolved from the June 2008 meeting. In addition, the following materials are included in their respective tabs:

- ☐ Tab F-1 – Questions provided to DOI
- ☐ Tab F-2 – Comparison of ED to Field Test Questionnaire Responses
- ☐ Tab F-3 – Natural Resources History of Project and Key Decisions

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:

- ☐ 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

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.

- ☐ Field Test Questionnaire Responses (in color to mark differences)
- ☐ Comparison of ED to Field Test Questionnaire Responses (in color to mark differences)

In preparation for the October meeting, please:

1. read the staff-prepared questions for DOI on pages 14 – 18 of Tab F-1;
2. refamiliarize yourself with DOI's response to the ED (provided in the June 2008 meeting binder at Tab H) and related field test questionnaire responses (provided in the February 2008 meeting binder at Tab D as well as this month's Tab F-2); and
3. determine if you have any additional questions you would like to ask the DOI representatives while they are present.

You may electronically access all of the briefing material at <http://www.fasab.gov/meeting.html>.

BACKGROUND

The 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. The CBO member believes that fair value is feasible and preferable. The CBO member'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, i.e., state governments and – at the component entity level – other federal agencies and the general fund of the U.S. Treasury. The liability would be calculated by assessing the total estimated petroleum royalties to be distributed to others.

When oil and gas resources are extracted and royalties are earned, revenue and a depletion expense equal to the earned revenue would be recognized by the federal government. When revenue collections are distributed a reduction in the liability for revenue distributions to others would be recognized. Gains and losses due to changes in the estimated quantity of proved oil and lease condensate, NGPLs, and gas reserves, 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.

See Tab F-3 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

Status of Tasks from June 2008 Meeting

TASK ONE:

Staff was directed to invite the Department of the Interior (DOI) to speak to the board members about its comment letter, the fieldwork test team's alternative proposal including why the team requested even more detail than was prescribed in the standard (e.g., splitting oil and lease condensate and computing separately), as well as the agency's thoughts on what a less prescriptive standard would mean and how it might apply to other resources under its domain. The board did not think a full blown public hearing was necessary but was very interested in talking to DOI before it finalizes the standard on oil and gas.

Status of Task One

Staff emailed the DOI representative on July 7, 2008, requesting their availability to speak to the board at either the August 20-21 or October 22-23 meetings.

DOI replied that they would be available for an October meeting. FASAB staff sent an informal listing of questions to DOI on August 15, 2008 and followed up with a formal memo on September 16, 2008. See Tab F-1 beginning on page 13 for a listing of the questions provided to DOI.

TASK TWO:

Staff was directed to determine whether the Energy Information Administration (EIA) would be providing information on proved reserves that underlie federal jurisdiction lands separately from other proved reserves. EIA is not currently reporting this information.

Status of Task Two

Staff researched the history behind the issue of EIA providing information on proved reserves under federal lands. Staff noted that the minutes to the March 2004 FASAB meeting state “Staff explained that currently, the EIA does 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 has now been tasked with the requirement to provide this information in its September 2004 reports. Therefore, because this information will be available, staff proposed that an estimated value for proved oil and gas reserves from lands under Federal jurisdiction might be capitalized. Mr. Patton asked how confident Mr. Wood was that the EIA could provide proved reserves information with great reliability. . . Mr. Wood indicated that the estimates are very reliable.” [Mr. John Wood, Director of Reserves and Production Division, Office of Oil and Gas, Energy Information Administration, Department of Energy, appeared before the board in March 2004 and August 2005].

Staff has reviewed the annual reports on U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves from 2003 through 2007 and the Oil and Gas Field Code Master List that the oil producers use to respond to EIA’s annual survey. Based on that review, **it does not appear that EIA has ever published or intends to publish data that distinguishes between oil and gas proved reserves that underlie federal jurisdiction lands and reserves not under federal lands.**

In addition, staff noted through a review of Appendix G of the most recently available annual report on U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves (2006) that EIA did not distinguish technically recoverable onshore oil and gas resources from federal lands as has been done for many years (table G1). This information was to be used to comply with the required supplementary information reporting requirements proposed in paragraph 32 of the oil and gas ED.

A memorandum dated September 26, 2007, was sent from Tom Allen to Mr. Wood to request the status of the availability of information (see letter immediately following this page). A response from Mr. Wood was not received.

Staff emailed Mr. Wood on Wednesday, July 9, 2008, to inquire whether information on proved reserves and technically recoverable resources that underlie federal jurisdiction lands would be available in the future. Staff followed up with a telephone call on Tuesday, July 15, 2008 and left a voice mail that referenced the July 9th email. Staff did not receive a response from EIA and subsequently followed up with an email to Mr. Owen Barwell, Department of Energy’s Deputy Chief Financial Officer on Monday, July 21, 2008, requesting assistance in obtaining a response from EIA. Staff again followed up with an email to Mr. Wood with a cc: to Mr. Barwell on October 2, 2008. This is in addition to earlier attempts by Rick Wascak to reach Mr. Wood.

Staff has not received a response to either emails or voice mails. It would seem that EIA does not intend to provide information on proved reserves under federal lands. In order to proceed with a standard on accounting for oil and gas, staff recommends that the board pursue other potential avenues for calculating an asset value (e.g., capitalizing flows).



September 26, 2007

John H. Wood
Director Reserves and Production Division
Office of Oil and Gas
Energy Information Administration
U.S. Department of Energy
1999 Bryan Street
Suite 1110
Dallas, TX 75201

Dear Mr. Wood,

The Federal Accounting Standards Advisory Board (FASAB) issued an exposure draft (ED) of a proposed Statement of Federal Financial Accounting Standards entitled *Accounting for Federal Oil and Gas Resources*. The proposed standards would result in the recognition of an asset referred to as “estimated petroleum royalties.” The source of the estimated quantity of proved reserves to be used by the Minerals Management Service (MMS) in calculating the value of estimated petroleum royalties is expected to be the Energy Information Administration (EIA). The general expectation is that quantity information would be available from an annual survey conducted by the EIA and that MMS would rely on this information in complying with the final standard.

At an August 2005 FASAB Board meeting and in various teleconference calls with you and representatives from the Department of the Interior (DOI), MMS, and FASAB staff, you indicated that the Congress had mandated the EIA to attain the capability to report the quantity of proved oil and gas reserves under the Federal government’s control separately from proved oil and gas reserves under the private sector’s control. In light of the expectation that MMS will rely on the EIA for this information, I am writing to request additional information regarding EIA’s progress and expectations with respect to attaining this information. While we recognize the demands your position places on your time, we are asking that you provide information relating to the following questions or concerns:

1. Please provide a reference to the law, regulation or policy directing EIA to attain additional information regarding proved oil and gas reserves under federal control.
2. Does the EIA currently have the estimated quantities of proved oil and lease condensate reserves, proved natural gas plant liquid reserves (NGPL), and proved dry natural gas reserves from Federal oil and gas resources on a regional basis? If not, please indicate when you expected to have the capability of providing these amounts separately from proved oil and gas reserves under the private sector’s control? (Note that the proposed implementation date for the accounting standards is October 1, 2009 (fiscal year 2010).)

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3. The quantity information on an annual survey is required to be provided to the EIA by oil and gas producers on April 15th following the end of the previous calendar year. The MMS is required to prepare and submit financial statements by November 15th for the year ended September 30th. Because the MMS will rely on quantity information the EIA received on April 15th of the current reporting year, please provide an estimate of the date following receipt of the survey information that the EIA would provide the necessary information to the MMS?
4. How would the EIA provide the information on proved oil and gas reserves to the MMS in order for the MMS to calculate the value of the estimated petroleum royalties? For example, would MMS be expected to rely on publicly available reports or would EIA be responsive to data requests directly from MMS?
5. Will the EIA have the capability to report the quantity of proved oil and gas reserves (i.e., the estimated quantities of proved oil and lease condensate reserves, proved NGPL reserves, and proved dry natural gas reserves) under the control of a Federal agency (e.g., the DOI) on behalf of Native Americans Indians separately from proved oil and gas reserves under the control of the federal government and private sector entities?

Please contact the Board's executive director, Wendy Payne, at 202 512-7357 or paynew@fasab.gov, as soon as possible to let us know if you will be able to provide the requested information.

Sincerely,



Tom L. Allen
Chairman

Cc: Wendy M. Payne, Executive Director
Rick Wascak, Assistant Director
Daniel Fletcher, Deputy CFO, Department of Interior
David Horn, Focus Leader Data Stewardship, Department of Interior

TASK THREE:

Staff was asked to research the history of the project to determine if there was a specific reason why standards for each of the natural resources categories were being separately and individually developed. Messrs. Farrell and Schumacher said they seem to recall that there was a reason why the board had decided that a standard for oil and gas had to be developed separately and could not be grouped together into one large standard on natural resources.

Status of Task Three

Staff searched in the task force report, meeting minutes, newsletters, and issue papers for any reference that would imply that the standards needed to be separately developed for each category.

The June 2000 Natural Resources Task Force Discussion Paper does not explicitly state that the resources cannot be addressed in one standard. On page 2, the report states “In the process of studying the natural resources, the task force classified the natural resources into categories. These categories were established for purposes of analyzing the resources.” On page 18, the report states “Within the existing scope of Federal accounting and reporting, there are multiple options for reporting information about natural resources owned by the Federal Government. Different options may be possible for a given natural resource according to the “stage” of the natural resource identified (i.e., undiscovered resources, not available for transfer, available for transfer, conveyed). Separate reporting options might also be chosen for various natural resources due to differences in the terms of sale or the attributes of natural resources. In addition, multiple options may be chosen for a single category of a resource (e.g. resources identified for sale might be both recognized and discussed in a footnote).”

The October 2002 staff issue paper contained a project plan that proposed developing accounting standards for all natural resources without reference to separately issuing standards by type of natural resource. The October 2002 minutes contain the following paragraph that implies that staff recommended the phased approach during the meeting.

Excerpt from October 2002 Meeting Minutes

Staff recommended reviewing each of the natural resource categories against the project objectives one at a time and to determine the amount and type of data available to meet those objectives. Staff specifically talked about reviewing the available data at each of the “stages” for each category to determine what is measurable and what is recognizable. Mr. Mosso stated that all of the resources included in the scope of the project are currently resources that are sold and producing revenues.

The December 2002 issue paper contained a project plan that specifically concentrated on oil and gas resources. The following excerpt from the transmittal memorandum states that staff recommended starting with oil and gas resources after the board suggested that staff initially address each type of natural resource separately and individually when developing accounting standards for natural resources.

Excerpt from December 2002 Meeting Materials

At the October FASAB meeting, Board members were asked to comment back to the Staff on the issues listed in the October meeting material, as well as any comments on those recommendations made by the task force in the June 2000 discussion paper. Based on comments received from various Board members, it appears many members are leaning towards recognizing natural resources owned by the Federal Government and information about them, providing recognition criteria is met. Board members also suggested that Staff initially address each type of natural resource separately and individually when developing accounting standards for natural resources. Staff recommends starting with oil and gas resources and to use the development of an oil and gas standard as a model for the other natural resources.

Staff has determined that the decision to focus on accounting for oil and gas resources first was made at some point in between the October and December 2002 board meetings. However, the reason for the decision is not documented other than in the basis for conclusions of the May 2007 Oil and Gas ED, which states “Federal oil and gas resources were addressed first because of the literature available in other domains, the extensive historical information on Federal lease programs and royalty collections, and the large amount of revenue earned in exchange for oil and gas resources.”

In conclusion, there does not appear to be any previously documented reason in FASAB’s files that would preclude the development of a comprehensive standard that addresses all types of natural resources. However, since the members voted to continue with the development of an individual standard on oil and gas, staff will not pursue a comprehensive standard on natural resources.

TASK FOUR:

Staff was asked to obtain revenue numbers for the different types of natural resources to determine the magnitude of other natural resource collections as compared to oil and gas.

Status of Task Four

The following table was provided to the board with the March 2004 materials. However, it did not contain a date or a source and was likely prepared by staff. It is not known if this schedule includes all of government or only a certain agency(ies). Staff will research and prepare updated information.

Comparison of Natural Resources Collections
(In millions)

Gas	\$5,372
Oil	2,373
Other Leasable and Saleable Minerals ¹	44
Timber	26
Locatable Minerals ²	19
Grazing	13
Total	\$7,847

¹ Generally occur in a solid state and include asphalt, sulfur, phosphate, potassium, sodium, gilsonite, and other minerals.

² This includes precious metals, ferrous metals, light metals, base metals, precious and semi-precious gemstones, and a vast array of industrial minerals.

Tab F-1
Questions provided to DOI

October 8, 2008

To: Members of the Board

From: Julia E. Ranagan

RE: Questions sent to DOI for October board meeting

FASAB staff sent an informal listing of questions to Department of Interior (DOI) on August 15, 2008 and followed up with a formal memo on September 16, 2008. Staff spoke with DOI on September 30, 2008 to obtain the status of DOI's response. Mr. David Horn, DOI representative, indicated that DOI will be present to speak to the board but would most likely not have a written response any time soon due to competing priorities with year-end reporting. If staff receives a written response from DOI any time prior to the board meeting, I will forward it to you immediately.



September 16, 2008

Mr. Daniel L. Fletcher
Director, Office of Financial Management
U.S. Department of the Interior
Office the Secretary
Washington, DC 20240

Dear Mr. Fletcher,

Thank you for your comment letter on FASAB's May 2007 exposure draft (ED), *Accounting for Federal Oil and Gas Resources*. I would also like to acknowledge the tremendous effort Interior's field test team put forth in its responses to the field test questionnaire in order to provide the board members with detailed information about potential problems and costs related to implementation of the proposed standards. These responses are invaluable to the board as part of its due process and the team members should be commended for their efforts.

To ensure that the board fully benefits from the views you expressed in your comment letter and field test questionnaires, the board would like to invite you and your team to speak to them at the October board meeting. I have tentatively scheduled your briefing on Thursday, October 23rd from 9:00 – 11:00 AM. Please let me know as soon as possible if this time is not possible.

I understand that your time is very valuable at this time due to the year-end reporting requirements. Therefore, I am providing a list of questions that are of most interest to the board. It would greatly improve the quality and outcome of the discussion if your team could provide a response to these questions in time for the board's review prior to the meeting. It is my hope that we can limit the discussion to only those items over which the members still have questions in order to make the most efficient use of everyone's time.

I would appreciate your response by Wednesday, October 1, 2008. You may email it to me at paynew@fasab.gov. If you have any questions, you may reach me at 202-512-7350 or Julia Ranagan at 202-512-7357.

Sincerely,

Wendy Payne
Executive Director

Questions

1. On page 3 of the ED View field test questionnaire, the team recommended that “the Statement and Appendices clarify that the major commodity categories in common between EIA and MMS be disaggregated, the averages computed separately, and then summed to derive the asset value.”

ED View field test questionnaire

“When computing regional average unit prices and regional average royalty rates by commodity, each component in common between EIA and MMS should be averaged separately and then summed. For example, when computing averages for oil and lease condensate, they should be computed separately, as their average unit price and rate are different. In order to have a more accurate estimate, they should not be folded together and then averaged, or the results may be notably different than if averaged separately and then summed. In the field study, folding just oil & lease condensate together and then computing the average made a \$500M difference in the overall asset value.” (ED View field test questionnaire, pg. 3.)

ED

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

- a. Based on the hypothetical asset value calculated for the ED view, \$500M would be less than one half of a percent. Is this considered material?
 - b. Considering that the number is an estimate, does the team believe this added specificity is needed for the financial statements to be fairly presented?
 - c. Does management plan to use this additional information for something other than external financial reporting?
2. On page 3 of the ED View field test questionnaire, the team recommended that wet and dry gas be computed separately and then summed together (similar to oil and lease condensate in question 1). However, the board had purposely specified dry gas in the ED because the proved reserves will be measured as pipeline quality gas that has had the liquids removed (i.e., dry gas). See excerpt from the minutes of the discussion below.

Excerpt from July 26-27, 2006 FASAB Minutes

Selection of the Correct Price Series for Natural Gas

Staff described the second CBO issue. Staff explained that the representatives from the CBO believe that, because the proposed standards already have specified that proved reserves of natural gas will be measured as pipeline quality, the total natural gas reserves should be valued at a “dry” gas price. (Gas can be priced either of two different ways. One is the value of

unprocessed (wet) gas, which still has the valuable NGLs mixed with it. The other is the value of processed (dry) gas—that is the pipeline-quality gas that has had the liquids removed.) Staff agreed with the CBO's proposal because the estimated quantities of proved gas reserves to be provided by the Energy Information Administration (EIA) for calculating the estimated petroleum royalties for gas will be dry gas quantities and, therefore, a dry gas price should be used. Staff added it would clarify in the standards that the dry gas price should be used in calculating the value of estimated petroleum royalties for gas.

It is the board's understanding that the total natural gas reserves should be valued at a "dry gas price." This is based on the understanding that (a) the proposed standards have specified that proved reserves of natural gas will be measured as pipeline quality; and (b) the estimated quantities of proved gas reserves to be provided by EIA for calculating the estimated petroleum royalties for gas will be dry gas quantities.

- a. Is the board's understanding correct?
 - b. If not, would the difference (wet and dry versus dry only) be considered material?
 - c. Considering that the number is an estimate, does the team believe this added specificity is needed for the financial statements to be fairly presented?
 - d. Does management plan to use this additional information for something other than external financial reporting?
3. Does the field test team believe that (a) the standard, as it is currently written, precludes or discourages the preparer from providing an even lower level of detail than what is called for in the standard (i.e., splitting wet and dry gas; oil and lease condensate; coal bed methane and dry gas) **or** (b) the recommended lower level of detail needs to be formally inserted into the standard in order to satisfy the auditors? If yes, please explain why.
4. The ED as it is currently written provides the principles regarding asset and liability recognition, but also includes extensive details regarding how to calculate and report the actual number (see pars. 37 through 45 and Appendix C).
 - a. What would it mean to Interior if the eventual final standard on oil and gas was a less prescriptive standard that only provided information on what should be reported rather than detailed guidance on exactly how to arrive at the reported number? For example, if pars. 37 through 45 and Appendix C of the ED were deleted, would Interior consider this to be an improvement over the current ED or a road block to implementation? Why or why not?
 - b. If a less prescriptive standard were issued, does Interior believe that it would need to request further implementation guidance? Why or why not?
 - c. If a less detailed standard were issued, does Interior think the standard could be broadly applied to other natural resources under Interior's domain?
5. Paragraph 38 of the ED requires that quantity information on proved reserves under federal land be populated from annual information published by EIA. However, as the field test team noted on pages 4 and 36 of the ED View field test questionnaire, this "information is presently not published by EIA." It is unclear whether EIA ever intends to

publish this information. Multiple correspondence from FASAB staff to EIA and the Department of Energy via memos, emails and phone calls have gone unanswered.

In its response regarding the issue, the field test team stated that “The MMS/OMM/BLM Team reached agreement on the estimation methodology described herein, and ascertained that in the absence of better information, this would be an acceptable method to use for implementation as well.” As noted by the team, the methodology uses a number of assumptions, including the assumption that production on federal lands versus non-federal lands does not vary widely.

- a. Were Interior’s auditors consulted regarding the estimation methodology described therein? If so, what was their response?
 - b. If not, does Interior believe that the estimation methodology developed by the field test team is a reasonable substitute for actual data on proved reserves under federal lands that could stand up to auditor verification?
 - c. As noted by the team on page 36 of the ED View field test questionnaire, the most current information available from EIA regarding reserve estimates that can be used to calculate the value at October 1 is based on data that is 21 months old. Does the field test team believe that the factor developed by the team experts reasonably overcomes this time lag?
6. Aside from the estimation methodology developed by the field test team, is Interior aware of other existing information that could be a reasonable surrogate for asset recognition and would be deemed an independent and reliable source? For example, before FASAB staff was told that EIA would begin publishing data on the federal share of proved reserves (which has not happened yet), FASAB had directed staff to pursue capitalization of the anticipated production stage revenue stream (flows).
7. On page 4 of the ED View field test questionnaire, the team performed queries from MRM’s published statistics module of royalties reported for the 12 sales (production) months in calendar year 2005 to obtain royalty information for federal leases. These queries included adjustments through September 2007. Comparing that data to the production data adjusted through February 2008 results in significant differences (from 2 – 24%) from what was reported as production data 5 months prior. If adjustments result in such large swings in the data, can this data be deemed reliable as of the date of estimation?
8. On page 6 of the ED View field test questionnaire, the team notes that “In deriving the averages, numerous factors had to be included, such as excluding royalty relief volumes and estimating the value of commodity received in kind and delivered to DOE to fill the Strategic Petroleum Reserve.” Similar to question 3, does the field test team believe that (a) the standard, as it is currently written, precludes or discourages the preparer from including such factors **or** (b) the additional factors need to be formally inserted into the standard in order to satisfy the auditors? If yes, please explain why.
9. On pages 9 – 10 of the ED View field test questionnaire, the team expresses concern over the impact that the ED will have on year-end processes, including the need for

recipients to make late adjustments to their corresponding receivables and intragovernmental eliminations. Please explain how significant you think this impact is. If the ED were issued as it is presently written, how would you propose to mitigate these late year-end adjustments?

10. On pages 14 – 15 of the ED View field test questionnaire, the team proposes an alternative to recognition of depletion expense due to (a) the large adjustments that are recorded in current year revenue but relate to prior year revenue; (b) rejected lines not processed in the system at year-end; and (c) manual accruals such as the royalty accrual and unmatched cash accrual that are not broken down into the detail required in the ED (e.g., oil vs. gas and onshore vs. offshore). The alternative proposal involves recognition of a depletion expense based on production for the 12 preceding sales months available at year end (July of the prior year through June of the current year).
 - a. Has a variance analysis been performed over a number of years to determine how large the difference is between using July through June data versus the October through September data once such data becomes available? If so, how large are the variances?
 - b. Were Interior's auditors consulted regarding the alternative methodology described therein? If so, what was their response?
 - c. If not, does Interior believe that the estimation methodology developed by the field test team is a reasonable substitute for actual data on depletion that could stand up to auditor verification?
11. On pages 13 – 17 of the ED View field test questionnaire, the team noted the extreme difficulty in providing an accurate measure of depletion expense as required by the ED, stating that "It currently could not be readily done with existing resources or information." Several board members have commented that the difficulty involved in providing this estimate is not an excuse for not doing it because they feel it is important to get this information out to the public. How would you respond to these board members?
12. On page 22 of the ED View field test questionnaire, related to the future royalty streams identified for sale, the team noted that "Key subject matter experts have indicated that this scenario is very highly unlikely" and subsequently did not devote resources to testing the requirements. The CBO representative had specifically requested this disclosure because he believed that that Congress may want to securitize some of the royalty revenues, that is, to sell a stream of future royalty revenue (see minutes from October 5 – 6, 2005 board meeting), and he would like to see the ED have some requirement to account for royalty streams that were sold below value; and, to have some idea of whether the nation was better off or worse off with the transaction. The other board members had agreed.
 - a. Please elaborate on the comment that "this scenario is very highly unlikely." Would this equate to a classification as remote?
 - b. Would it not be appropriate for the ED to include a requirement in anticipation of the possibility that it may happen?

13. On page 33 of the ED View field test questionnaire, as well as in Interior's comment letter, it is recommended that implementation of the standard be delayed until all commodities and related business activities are addressed. Given that oil and gas is most likely the most material of all of the commodities, what is the primary benefit to be gained from delaying the standard?
14. Interior's comment letter to the ED states "The Team reached consensus that the most appropriate method for valuing the asset 'estimated proved reserves' is neither the view presented in the exposure draft nor the alternative view, but rather a modified alternative method, called the 'present value method.' This valuation method, based upon the deterministic model for ascertaining quantity, is presented in detail in the field test questionnaire. It is considered a superior method because the value of total proved reserves at any point in time must include a factor to account for the reserves that cannot be extracted and recognized as revenue at the measurement date. By estimating production declines, potential additions, and estimated depletion, the net estimated present value of the asset will provide the readers with a more realistic picture of the assets value at the financial reporting date."
 - a. This method would need to rely on a significant amount of alternative estimations, especially given the EIA's failure to provide additional information related to proved reserves under federal lands. Were Interior's auditors consulted regarding the 'present value' methodology described therein? If so, what was their response?
 - b. If not, does Interior believe that the 'present value' methodology developed by the field test team is a reasonable substitute for actual data on proved reserves under federal lands that could stand up to auditor verification?
15. Are there any other issues that were raised in either the field test questionnaires or the comment letters that Interior would like to emphasize to the board members?

Tab F-2
Comparison of ED to Field Test
Questionnaire Responses

Summary Comparison of ED to ED View and PV View Field Test Questionnaires

Key

ED = May 2007 Exposure Draft (ED), *Accounting for Federal Oil and Gas Resources*

ED View = ED View field test questionnaire provided by DOI

PV View = Present Value (PV) View field test questionnaire provided by DOI

This comparison is a summary of the detailed comparison of the field test questionnaires beginning on page 36.

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
Reliance on Data Provided by EIA	Reliant on proved reserves data provided by EIA.	Reliant on proved reserves data provided by EIA.	Reliant on proved reserves data provided by EIA.
Components Separately Computed	Group oil and lease condensate together.	Compute oil and lease condensate separately and then sum.	Recommends that estimates of proved reserves be divided according to commodity (crude oil, lease condensate, and natural gas – wet after lease separation), and, in the Gulf of Mexico (GOM), further for each commodity by the water depth category of the field. (DOI acknowledges that they have had difficulty communicating with EIA to determine if EIA can provide such a breakdown of proved reserves.)
Wet vs. Dry Gas	Base calculation on dry (pipeline quality) gas.	Compute wet and dry gas separately and then sum.	The Exposure Draft calls for the estimation of royalties from proved reserves of natural gas plant liquids (NGPL) along with royalties from proved reserve estimates of crude oil, lease condensate, and presumably dry natural gas. The EIA reports estimates of natural gas reserves in two different forms. One form is Dry Natural Gas which is the volume of natural gas after the natural gas liquids have been removed. The other form is Natural Gas, Wet After Lease Separation which is the volume of natural gas prior to the natural gas liquids being removed. Should dry gas proved reserves be used for the royalty estimates, NGPL proved reserve estimates should also be used to capture the entire hydrocarbon value. However, wet gas volumes and values are greater than dry gas volumes and values because of the

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
			<p>additional content of NGPL in the wet gas. MMS prefers the use of the wet gas estimates because they replicate the form and the point in time when the royalty valuations are made. Further, MMS/OMM reservoir engineers and geoscientists are very experienced in dealing with and estimating reserves and production in terms of wet gas as all MMS/OMM datasets are in terms of wet gas. Finally, the use of dry gas and NGPL creates possibly insurmountable problems in properly allocating reserves back to their source fields, affecting value estimations at the proper royalty rates, and in constructing production profiles. Adding values for NGPL to this would amount to a double counting of the values of NGPL. MMS has used only wet gas proved reserves estimates (and no estimates of NGPL) in its trial analysis and highly recommends this procedure for these calculations.</p>
Present Value Of Royalties Received Over Time	N/A	N/A	<p>In order to effectively calculate the present value of federal royalties, it needs to be estimated how those royalties will be received over time. To determine this, one needs to project how the proved reserves estimates will be produced over time. EIA proved reserve estimates include reserves from which federal royalties will be received, as well as, reserves from which royalties will not be received due to various royalty relief policies.</p> <p>The model that MMS has created can be used to project the future production of the EIA proved reserve estimates assuming an exponential decline at a rate of the modeler's choice. The model also receives, as inputs, annual estimates of royalty free production from royalty relief. The annual production estimates of the proved reserves calculated by the model are then reduced by the royalty free annual volumes prior to the royalty calculations.</p>

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
Estimate of Future Gas Prices	N/A	N/A	<p>Of equal importance in the estimation of the present value of royalties to the production estimates are the estimates of future oil and gas prices. MMS-OMM recommends that independently generated and commonly available price estimates be used. The MMS-OMM already uses and is familiar with the OMB economic assumptions that are generated semi-annually for the President's Budget. For the purpose of the trial analysis performed, the oil and gas prices from the OMB's "Economic Assumptions for the 2008 Mid-Session Review" were employed.</p> <p>A minor limitation to those parameters is that the projections are only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary.</p> <p>Depending on the locations associated with the price parameters, the prices will have to be adjusted to approximate average wellhead prices for each OCS Region (GOM, Pacific, Alaska North Slope). Such an adjustment has two components, an adjustment to a regional landed average price, then a transportation allowance to a regional wellhead average price. The first adjustment to a regional landed average price will be conducted by observing the historical average relationship of the price series being considered (e.g., United States average wellhead natural gas price) to the average regional landed natural gas price (e.g., Henry Hub). From these observations, factors and/or trends in these price relationships can be deduced and applied to the price projections to result in projections of regional landed prices. Such relationships need to be studied in detail prior to "going live" with the present value estimates. For the purpose of the trial analysis performed, it was assumed that the OMB's average</p>

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
			imported and domestic refiner's acquisition cost for oil and the average wellhead price for imported, inter-, and intra-State natural gas estimates would be equivalent to the average landed prices of oil and gas for each Region. The OMB's price projections are expressed in nominal terms.
Transportation Allowances	N/A	N/A	<p>The second component of the price adjustment is the transportation allowances. Lessees pay royalties based on the value of their production at the wellhead. Since the price adjustment above resulted in a regional average landed price, these need to be converted to regional average wellhead prices by subtracting a regional average transportation allowance.</p> <p>One approach would be for MMS-MRM to determine the necessary average historical transportation allowances claimed by lessees on royalty bearing production for the previous 12 sales months. Such averages would be weighted by the volume of production using that allowance, would be by commodity, and for the GOM, would be by the royalty rate of the contributing leases. The assumption would then be that the resulting previous 12-month average transportation allowances would also apply to all future production within the same category. Because the price projections used are nominal values, the transportation allowances would be increased in the future with inflation.</p> <p>This method was employed in the trial analysis, though further study of the accuracy of this approach would be necessary prior to any official calculations.</p>
Discount and Inflation Rates	N/A	N/A	As for product prices, MMS-OMM recommends that independently generated and commonly available discount and inflation rates be used in calculating the royalty present value. A public sector discount rate for the federal government should be readily available and applicable for this purpose. For the purpose of the trial

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
			<p>analysis, MMS assumed a discount rate equal to the federal government's interest rate paid on its long-term borrowing as the discount rate. OMB's projection of the 30-year Treasury Bill rate was used. For inflation, MMS assumed OMB's projection of the GDP Price Index for the trial analysis.</p> <p>As was the case for OMB's oil and gas price projections, projections of these parameters by OMB are also only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary.</p>
Present Value Calculations	N/A	N/A	<p>For all federal offshore areas, MMS proposes the use of the following method to estimate the present value of future federal royalties from proved reserves:</p> <ol style="list-style-type: none"> 1) By federal OCS Region, project production of DOE-EIA proved oil/condensate, and wet natural gas reserves estimates over time until depleted, 2) In GOM, also project separately for one-sixth and one eighth royalty rate leases (use water depth subsets of >400m and <400m as proxy), 3) Where applicable, determine adjustments needed to reflect projected royalty free production from royalty relief leases and modify as appropriate the total projections above, 4) Calculate future regional landed prices from price projection (OMB or other) assigned by FASAB using historical price relationships to make further adjustments, 5) Calculate future wellhead landed prices from regional landed prices using average actual transportation allowances claimed for the previous 12-month period.

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
			<p>6) For production for each Regional commodity by royalty rate, calculate annual royalties as follows: $(\text{Annual Production less adjustments for Annual Royalty Free Production}) * (\text{Annual Regional Landed Price} - \text{Average Transportation Allowance}) * \text{Royalty Rate}$</p> <p>7) For a given vector of calculated future annual royalty estimates, determine the present value of the royalty revenue stream assuming the discount rate (OMB 30-year Treasury Bill or other) assigned by FASAB.</p>
Selection of Regions	Par. 17 states that “the regions used in determining and reporting regional amounts or factors shall be collaboratively developed by all the component entities involved in oil and gas resource activities.”	Regions were divided simply into onshore and offshore. However, for implementation of the Statement, we would recommend a greater degree of division, to better reflect price differentials in different basins and regions.	Not specifically discussed.
Data Provided by EIA	Par. 38 states that “based on quantity information from an annual survey conducted by the EIA, the estimated quantities of proved oil and lease condensate reserves from Federal oil and gas resources are to be added together in each region, the estimated quantities of proved NGPLs reserves from Federal gas resources are to be added together in each region, and the	<p>The first step was to determine what portion of all proved reserves fall under federal domain, before the federal royalty share of those proved reserves could be estimated. This information is presently not published by EIA, so an estimation methodology had to be developed.</p> <p>Step 1: MRM performed queries from its published statistics module of royalties reported for the 12 sales (production) months in calendar year 2005, which would include any adjustments for sales months in that time frame made up through September, 2007, when the final refined queries were run.</p>	Substantially the same as ED View Field Test Questionnaire; however, offshore quantities are under federal domain by definition, so were excluded from the estimation process. This differs from the computation method developed in the ED.

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
	estimated quantities of proved gas reserves from Federal gas resources are to be added together in each region.”	<p>Step 2: MMS Custodial Reporting Branch (CRB) obtained the published EIA 2005 Annual Report of total nationwide estimated proved reserves, both federal and non-federal.</p> <p>Step 3: MMS CRB then estimated the federal portion of onshore proved reserves by using a ratio of 2005 onshore estimated production nationwide published by EIA, compared to 2005 total production volumes from federal leases reported to MRM on royalty reports.</p> <p>Step 4: The ratios of federal to total 2005 production then became a proxy for the ratio of federal proved reserves to total proved reserves reported by EIA.</p>	
Asset Value	Par. 18 states that “The values of estimated petroleum royalties calculated for oil and lease condensate on a regional basis, NGPLs calculated on a regional basis, and gas calculated on a regional basis shall be added together to provide the total value of estimated petroleum royalties for the Federal government.”	Step 5: To compute the estimated beginning balance of the federal royalty share of the asset to capitalize, MMS CRB utilized the existing royalty reported data for sales months in calendar year 2005 which had been provided by MRM to aid in computing the estimated quantity, as it had already been refined and was available. This was done solely for illustrative purposes to obtain a beginning balance. In actual practice this unique scenario would not exist, where the EIA published data and the MRM reported royalty data would cover the exact same time frame for computing the averages. In practice, the MRM reported data used to compute the averages would be more current, and reflect more current volumes, prices and rates. It would be based upon the preceding 12 sales months royalties reported for which royalty	<p>Since the federal proved reserves derived from EIA published data were for FY 2005, the amount of production from FY 2006 was subtracted from federal proved reserves before starting additional calculations. Using prior years’ production data and estimates on new wells permitted and drilled each year, an estimated yearly production was estimated for each year. The estimates in new permits approved and wells drilled were based on the following parameters:</p> <ul style="list-style-type: none"> • 5% of Applications for Permit to Drill (APDs) processed are Indian • 84% of the federal APDs processed are approved • 85% of the federal Approved APDs are drilled • 90% of the wells drilled are productive • 10% of the productive wells are oil • 90% of the productive wells are gas

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Field Test Questionnaires			
Issue Area	ED	ED View	PV View
		<p>production data is available, or July through June when measured at September 30.</p> <p>Step 6: Average royalty rates were computed by dividing the total regional royalty value by the total regional sales value by commodity categories for sales months in calendar year 2005.</p> <p>Step 7: Average unit prices were similarly derived by dividing the total regional sales value by the total regional sales volume.</p> <p>Step 8: The asset value was computed by simply multiplying average rate X average unit price X estimated quantity for each region and commodity category. The totals were then summed to arrive at the total asset estimated value to capitalize.</p> <p>In deriving the averages, numerous factors had to be included, such as excluding royalty relief volumes and estimating the value of commodity received in kind and delivered to DOE to fill the Strategic Petroleum Reserve (SPR). For purposes of the study, since SPR royalty reports contain volumes but no value, the average rate and unit price computed for Gulf oil were imputed to the SPR volumes, and the value computed from these averages. In practice, this method could be used, or alternatively the volumes could be obtained from royalty reports, the value from the manual journals used to record the activity in the period, and the average rate and average unit price then computed. The summary calculations are presented in Illustration 1.</p>	<ul style="list-style-type: none"> • 85% of the productive wells begin production in the first year • 10% of the productive wells begin production in the second year • 4% of the productive wells begin production in the third year • 1% of the productive wells begin production in the fourth year • Average oil well produces 7,300 barrels per year or 20 barrels per day • Decrease of 10% per year for oil production • Decrease of 10% per year for gas production • Average gas well produces 80,000 MCF per year or 219 MCF per day • APDs processed in 2008 - 2011 are set at 11,500 and then start a slow decline of 500 APDs per year. <p>Once yearly production estimates were established they were subtracted from the federal proved reserves until the proved reserves were zero. A similar present value method was applied to onshore quantities. A yearly estimated price for oil, natural gas and natural gas liquids was used based on OMB estimates. Since the OMB estimates only went out for ten years, prices were estimated based on the trend of the OMB estimates after that. A royalty rate based on historic data from MMS was used to estimate the royalty rate. The data from MMS on the royalty rate appeared to be constant, so no change in the royalty rate was made for each year. A standard discount rate was used to bring future dollars back to today dollars.</p> <p>The estimated yearly production was multiplied by estimated average yearly price, the royalty rate and the</p>

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
			discount rate for that year. All of these totals were added together to come up with the estimated value of each commodity (oil, natural gas and natural gas liquids). These total were added together to come up with a estimated total value of the federal onshore oil and gas proved reserves.
Effect of Intermediate Production Between the Effective Date of the Reserves Estimate and the Effective Date of the Booked Value	N/A	Discussed in comment section.	<p>In the 21 months that will transpire between the effective date of the reserves estimates and the effective date of the value estimate, the reserves estimate will have been reduced by any depletion of the reserves through production. In addition, over the same time period, the reserves estimate will have been increased through any additions to reserves that naturally occur as accumulations are explored and developed.</p> <p>The intermediate production that occurs between the effective date of the reserve estimates and the effective date of the booked value represents a true and measurable reduction in the proved reserves estimate for which the royalty value will have been received and accounted for elsewhere. Booking the value of this production as proved reserves would amount to an overstatement of this asset. The MMS proposes reducing the proved reserves by the volume of the intermediate production. At the time for calculating the book value of the proved reserves for FASAB, the MMS will have production volume estimates for approximately 18 of the 21 months of intermediate production and proposes to use production projections for the remaining months.</p> <p>MMS believes it would be inconsistent to reduce the value of the royalty stream by the value of the intermediate production without also including a corresponding increase from proved reserves that would be almost certainly added between the effective date of the proved reserve estimates and the effective date of</p>

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires																					
Issue Area	ED	ED View	PV View																				
			<p>the booked value. Unlike the intermediate production, however, which can be mostly measured, intermediate increases of the EIA proved reserve estimates are not available for these calculations. The MMS proposes that estimates of the reserves additions be employed and offers the following methodology for estimating revised reserves estimates based on the EIA estimates but are effective the date of the booked asset value.</p> <p>The methodology employs the historical relationship between the volume of production of proved reserves and the volume of reserves additions to proved reserves. The EIA has estimated and reported the proved reserves of the federal OCS areas for many years. In its annual presentation of its reserves estimates, EIA reports the previous year's reserve estimate, all additions to that previous year's estimate, and all reductions to that previous year's estimate (including production). The following are EIA data that track the reserves estimate and corresponding revision categories for crude oil proved reserves of the Pacific federal OCS for 2005.</p> <table><tr><td>Proved Reserves as of 12/31/2004</td><td>547 MMbbl</td></tr><tr><td colspan="2">Changes in Reserves During Year</td></tr><tr><td>Adjustments (+,-)</td><td>-1 MMbbl</td></tr><tr><td>Revision Increases (+)</td><td>3 MMbbl</td></tr><tr><td>Revision Decreases (-)</td><td>81 MMbbl</td></tr><tr><td>Sales (-)</td><td>0 MMbbl</td></tr><tr><td>Acquisitions (+)</td><td>0 MMbbl</td></tr><tr><td>Extensions (+)</td><td>0 MMbbl</td></tr><tr><td>New Field Discoveries (+)</td><td>0 MMbbl</td></tr><tr><td>New Reservoir Discov in Old Fields (+)</td><td>0 MMbbl</td></tr></table>	Proved Reserves as of 12/31/2004	547 MMbbl	Changes in Reserves During Year		Adjustments (+,-)	-1 MMbbl	Revision Increases (+)	3 MMbbl	Revision Decreases (-)	81 MMbbl	Sales (-)	0 MMbbl	Acquisitions (+)	0 MMbbl	Extensions (+)	0 MMbbl	New Field Discoveries (+)	0 MMbbl	New Reservoir Discov in Old Fields (+)	0 MMbbl
Proved Reserves as of 12/31/2004	547 MMbbl																						
Changes in Reserves During Year																							
Adjustments (+,-)	-1 MMbbl																						
Revision Increases (+)	3 MMbbl																						
Revision Decreases (-)	81 MMbbl																						
Sales (-)	0 MMbbl																						
Acquisitions (+)	0 MMbbl																						
Extensions (+)	0 MMbbl																						
New Field Discoveries (+)	0 MMbbl																						
New Reservoir Discov in Old Fields (+)	0 MMbbl																						

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		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
			<p>Estimated Production (-) 27 MMbbl</p> <p>Proved Reserves as of 12/31/2005 441 MMbbl</p> <p>Since the MMS will have a reliable estimate of the intermediate production, a method was devised to determine the EIA historical average proved reserves change expressed in proportion to historical average production of proved reserves. For example, between 1992 and 2005, EIA's proved oil and lease condensate reserve estimates for the deep water Gulf of Mexico increased by 2.771 billion barrels. Correspondingly, over that same 14-year period, EIA reports that 2.833 billion barrels of oil and lease condensate were produced from the same area. This indicates over that time period, for every barrel of production that occurred, the oil reserves estimate increased by 97.81% of a barrel ($2.771/2.833 = 0.9781$).</p> <p>Potentially, this concept can be confusing because of the varying terminology used in the above description. It is important to realize that the reserves estimate adjustment methodology suggested above accounts for reserves additions as well as reserves reductions, including production. This is because the reserves estimate adjustment factor proposed is the determination of the change in the reserves estimate expressed in proportion to the volume of production over the same time period. The important concept to remember is that the volume of production is also a component of the change in reserves estimate.</p> <p>Using these calculated averages for each appropriate area, and the volumes of intermediate production, MMS proposes that the EIA proved reserves estimates, effective 21 months prior to the effective date of the booked value, be adjusted to a value that is reflective of the effective date of the booked asset value. Continuing</p>

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
			<p>with the same example of Gulf of Mexico deep water proved reserves of oil and lease condensate, the proved reserve estimate was 3.626 billion barrels as of December 31, 2005. The MMS estimates 592 million barrels of intermediate deep water GOM oil and lease condensate production over the 21 months between December 31, 2005 and October 1, 2007. Applying the average reserves change to production ratio, the December 31, 2005 GOM oil and lease condensate proved reserve estimate of 3.626 billion barrels would increase by 579 million barrels (592 million barrels produced * 97.81% = 579 million barrels reserves change) to 4.205 billion barrels by October 1, 2008.</p> <p>The MMS/OMM acknowledges improvements over this method include the receipt of EIA's proved reserves estimates sooner. That is, receiving estimates that are only 9 months out of date, instead of 21 months. This would involve the receipt of the necessary estimated prior to EIA publishing the values. Another improvement is if EIA could provide all of the above data in exactly the form and format needed which would mean by water depth category in the federal offshore Gulf of Mexico, and perhaps for federal only proved reserves for the federal onshore.</p> <p>This adjustment factor is included in the offshore calculations. A production decline factor is included in the onshore calculations, but no factor was included for potential increases or additions. This highlights a significant issue requiring resolution before implementing any valuation methodology, regardless of the valuation method selected</p>
'Earned Revenue' and Depletion Expense	Par. 23 states that "Royalties from the production of proved oil and lease condensate, NGPLs,	This introduces many complexities, including whether or how to include estimates such as the 'royalty accrual' and the relationship between revenue recorded in the current fiscal	Substantively the same as discussion in ED View Field Test Questionnaire.

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
	<p>and gas reserves from Federal oil and gas resources shall be recognized as exchange revenue on the Statement of Net Cost by the component entity that is responsible for collecting the royalty revenue. At the same time, an amount equal to the royalty revenue shall be recognized as depletion expense on the Statement of Net Cost of the component entity that is responsible for collecting the royalty revenue; and, the value of estimated petroleum royalties shall be reduced by the depletion expense amount.”</p>	<p>year for royalty reporting adjustments made to prior years and current year depletion expense.</p> <p>Revenue earned by the collecting entity generally consists of amounts reported or billed, cash for which no royalty report has been received (unmatched cash), and amounts accrued as estimates. There is not a simple means at this time to obtain detail which reconciles to the general ledger and financial statements, of all components of earned revenue specifically related to oil and gas and more specifically related to offshore vs. onshore leases.</p> <p>The recommended alternative is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end; July through June (received through August, fully available in September). This would preclude the need to include estimates in the depletion calculations (discussed below), and would represent a realistic value of true asset depletion based on actual royalty reporting. Revenue earned would not be a perfect match in the fiscal year, but in this case it should not, because depletion in the current year should not be linked to prior adjustments not related to the current year. To do otherwise would include prior period adjustments not related to depletion in the year, and would involve complex and extensive inclusion of current year estimates that also include prior period adjustments. This method would likely yield a more accurate picture of current asset depletion over a year span. This method would also provide the ability, with sophisticated</p>	

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
		<p>queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, onshore vs. offshore and other necessary details.</p> <p>Another alternative would be to record depletion based solely upon all royalty lines received and accepted during the fiscal year, excluding all accruals and regardless of sales month. Again, revenue earned would not be a perfect match in the fiscal year, because accruals would be excluded. But including all lines accepted in a year would eliminate the need to include complex and extensive current year-end estimates for which disclosure detail is not available (see discussion below) because actuals over a 12 month span would be fully included. This method would, however, include all adjustments to prior reporting received in the current fiscal year, and while it may provide a closer tie to actual revenue reported in the financial statements, it would not be as fair a measure of asset depletion in the year. This method, like the recommended method above, would provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, and other necessary details.</p> <p>The matrix in Illustration 3 presents some of the key components of 'earned royalty revenue' presently recorded by MMS, and demonstrates how the earned royalty revenue value was estimated for the illustrative pro forma entries. It must be noted that in actual practice, the previous year-end estimate would</p>	

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

		Field Test Questionnaires	
Issue Area	ED	ED View	PV View
		be reversed in the subsequent year, so that actual revenue recorded in any given year related to estimates would essentially reflect the change associated with those estimates over the year. In this example, for the study, the full values were presented, to give the reader a general idea of the relative sizes of the estimates under discussion.	

Listing of DOI Comments

This is a listing of DOI's extensive comments that begin on page 70. The majority of these comments have not been discussed by the board members at a previous meeting. It is recommended that you read the summary of differences between the ED, ED View field test questionnaire, and PV View field test questionnaire prepared by staff beginning on page 20 as well as DOI's comments that begin on page 70.

- Availability of EIA Data
- Timing of EIA Published Data – Adjustment Factors
- Obtaining, Classifying, and Stratifying the Royalty Reported Data
- Calculating Average Prices and Average Rates
- Commodity Categories Computed Separately
- Wet Gas vs. Dry Gas
- Settlement Amounts
- Invoiced Amounts
- Royalties and Depletion Expense on Statement of Net Cost
- New Accounting Treatment, SGL Accounts and Accounting Models Required
- New Fund or Reporting Exception Required
- Exchange Revenue Recognition (Payments to States and Counties)
- Rescission of Amendments to SFFAS 7 Related to Bonus Bid, Rent, and Royalty Revenues
- Long-term vs. Short-term Liabilities
- Fiduciary Reporting Requirements
- Potential Impacts to BLM Accounting and Custodial Statement
- Component Entity Disclosures
- Component Entity Required Supplementary Information

Detailed Comparison of ED View and PV View Field Test Questionnaires

The field tests prepared by the Department of Interior (DOI) provided pro forma transactions for the following ten accounting events for both the (a) proposed standards presented in the exposure draft (ED) as well as (b) the alternative view presented in paragraphs 114 through 127 of the Basis for Conclusion in the ED. The alternative view is being referred to as the present value (PV) view.

1. recording the initial value of the estimated petroleum royalties;
2. recording the one-fifth bid amounts;
3. recording the remaining payment by the successful bidder and the annual rental fee and the related liability for revenue distributions to others;
4. recording the annual rental fee from pre-existing leases and the related liability for revenue distributions to others;
5. refunding the unsuccessful bidders' bonus bid deposits;
6. recording earned royalty revenue and depletion expense;
7. recording the collection of royalty revenue;
8. recording the distribution of bonus bid, rent, and royalty collections and the reduction in the liability for the revenue distributed to others;
9. recording the sale of future royalty streams identified for sale and the related change in the liability for revenue distributions to others; and,
10. recording the annual valuation of estimated petroleum royalties and the related change in the liability for revenue distributions to others.

Key

- Text in ED View field test questionnaire differs from the ED
- Text in PV View field test questionnaire differs from the ED View field test questionnaire

ED	PV
1. Record the initial value of the estimated petroleum royalties and the related liability for revenue distributions to others. (There is a material difference between the field test views; read narrative that follows for more information.)	
The initial value of estimated petroleum royalties used in this pro forma transaction is calculated for illustrative purposes only. The value of the federal government's estimated petroleum royalties was calculated based on the valuation of oil and lease condensate	The initial value of estimated petroleum royalties used in this pro forma transaction is calculated for illustrative purposes only. The value of the federal government's estimated petroleum royalties was calculated based on the PV method developed by the Team, and described in

ED	PV
<p>estimated petroleum royalties, natural gas plant liquids (NGPLs) estimated petroleum royalties, and gas estimated petroleum royalties on a regional basis. Formulas to be used to calculate the estimated petroleum royalties for oil and lease condensate, NGPLs, and gas on a regional basis are as follows:</p> <p>For oil and lease condensate (Computed Separately and then Summed):</p> $\text{Regional Estimated Quantity of Proved Oil and Lease Condensate Reserves} \times \text{Regional Average First Purchase Price for Oil and Lease Condensate} \times \text{Effective Regional Average Royalty Rate for Oil and Lease Condensate} = \text{Regional Estimated Petroleum Royalties for Oil and Lease Condensate}$ <p>For NGPLs:</p> $\text{Regional Estimated Quantity of Proved NGPLs Reserves} \times \text{Regional Average First Purchase Price for NGPLs} \times \text{Effective Regional Average Royalty Rate for NGPLs} = \text{Regional Estimated Petroleum Royalties for NGPLs}$ <p>For wet and dry gas (Computed Separately and then Summed):</p> $\text{Regional Estimated Quantity of Proved Gas Reserves} \times \text{Regional Average Wellhead Price for Gas} \times \text{Effective Regional Average Royalty Rate for Gas} = \text{Regional Estimated Petroleum Royalties for Gas}$ <p>When computing regional average unit prices and regional average royalty rates by commodity, each component in common between EIA and MMS should be averaged separately and then summed. For example, when computing averages for oil and lease condensate, they should be computed separately, as their average unit price and rate are different. In order to have a more accurate</p>	<p>detail below.</p> <p>Methodology for Estimating the Present Value of the Federal Royalties from Federal Proved Reserves (Present Value Method)</p> <p>Offshore</p> <p>The following methodology is offered as a workable solution to the Alternative View proposal that a “Fair Value” method be used to value future federal royalty receipts from proved oil and gas reserves on federal lands. This methodology has been proposed by the MMS Offshore Minerals Management (MMS-OMM). A model has been constructed and tested, though the results only apply to federal offshore royalties which fall under the MMS-OMM domain. Federal agencies responsible for management of federal onshore oil and gas proved reserves concurred with this proposal, and also applied a similar methodology for valuing federal onshore proved reserves for the FASAB study.</p> <p>Responsibility for estimating the present value of the federal share of federal OCS proved reserves would reside primarily within the OMM Resource Evaluation (OMM-RE) umbrella with assistance from the Department of Energy – Energy Information Administration (EIA), MMS – Minerals Revenue Management (MMS-MRM), and the MMS - OMM Economics Division (OMM-ED).</p> <p>Proved Reserves Estimates</p> <p>The basis for these calculations would be the same as is the Majority Proposal. That is, the present value of the future federal royalties revenue stream would be calculated using the Department of Energy, Energy Information Administration (EIA) estimated volumes of proved reserves.</p>

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
<p>estimate, they should not be folded together and then averaged, or the results may be notably different than if averaged separately and then summed. In the field study, folding just oil & lease condensate together and then computing the average made a \$500M difference in the overall asset value. We recommend that the Statement and Appendices clarify that the major commodity categories in common between EIA and MMS be disaggregated, the averages computed separately, and then summed to derive the asset value.</p> <p>Royalty information reported to MMS/MRM is reported as the commodity was sold or removed from the lease. This is important to note, as some assumptions had to be made in conducting the study of the ED view, and will exist at implementation. As regards wet vs. dry gas, MMS can only retrieve it as it was reported.</p> <p>For purposes of the field test of the ED view, regions were divided simply into Onshore and Offshore. However, for implementation of the Statement, we would recommend a greater degree of division, to better reflect price differentials in different basins and regions.</p> <p>The first step was to determine what portion of all proved reserves fall under federal domain, before the federal royalty share of those proved reserves could be estimated. This information is presently not published by EIA, so an estimation methodology had to be developed. The MMS/OMM/BLM Team reached agreement on the estimation methodology described herein, and ascertained that in the absence of better information, this would be an acceptable method to use for implementation as well.</p> <p>In order to maintain some consistency and comparability with the most recent available EIA data published for calendar year 2005, MRM performed queries from their published statistics module of royalties reported for the 12 sales (production) months in calendar</p>	<p>Ideally, such estimates of proved reserves would need to be divided according to commodity (crude oil, lease condensate, and natural gas – wet after lease separation), and, in the Gulf of Mexico (GOM), further for each commodity by the water depth category of the field. For example, the proved reserves estimates for oil and lease condensate would further have to be divided into proved reserves from fields in water depths less than 400 meters and proved reserves from fields in water deeper than 400 meters. The water depth subdivision at 400 meters is to facilitate the calculations using the appropriate royalty rate as typically, for pre-2007 GOM leases, those in water shallower than 400 meters have a one-sixth royalty rate and those in deeper than 400 meters have a one-eighth royalty rate. Beginning with GOM leases sold in 2007, all have a one-sixth royalty rate, regardless of water depth. Proved reserves from other federal OCS Regions would not need to be divided according to water depth as those regions, as typically they have a single royalty rate per Region.</p> <p>In reality, the DOI has had difficulty communicating with the EIA to determine if they can comply with the proved reserves data needs expressed above. The MMS/OMM strongly recommends that an agreement be reached with the DOE/EIA to provide the necessary proved reserves data in the appropriate form and format for this or any method adopted for the reserves valuation. Alternatively, the MMS has devised a means for estimating the proportions of EIA proved reserves for the GOM applicable to royalty rates of one-sixth and one-eighth. This has been accomplished by applying the water depth proportions from the most recent MMS proved reserves estimates to the published proved reserve estimates from EIA.</p> <p>Production Profiles</p> <p>In order to effectively calculate the present value of federal royalties, it needs to be estimated how those royalties will be received over time. To determine this, one needs to project how the proved reserves</p>

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<p>year 2005, which would include any adjustments for sales months in that time frame made up through September, 2007, when the final refined queries were run. Data obtained included region, product code, commodity description, reported sales volume, reported sales value, and reported royalty value.</p> <p>MMS Custodial Reporting Branch (CRB) obtained the published EIA 2005 Annual Report of total nationwide estimated proved reserves, both federal and non-federal. MMS CRB then estimated the federal portion of onshore proved reserves by using a ratio of 2005 onshore estimated production nationwide published by EIA, compared to 2005 total production volumes from federal leases reported to MRM on royalty reports. The ratios of federal to total 2005 production then became a proxy for the ratio of federal proved reserves to total proved reserves reported by EIA. Offshore quantities are under federal domain by definition, so were excluded from the estimation process. This differs from the computation method developed in the ED.</p> <p>Royalty reported data was used for volumes sold or extracted from the lease, rather than straight production data, because production (OGOR) data is not broken out in the required detail, and it is not as up to date as royalty reported data.</p> <p>It is important to consider that many assumptions had to be made in developing this model. As regards wet vs. dry gas, MMS can only retrieve the data as it is reported by industry, as it is sold or removed from the lease. Below describes the stratification of data that was retrieved by MRM for our field study, and how each commodity was categorized.</p> <p>The Oil and Lease Condensate category contains product codes of:</p> <table><tr><td>01</td><td>Oil</td><td>(Oil)</td></tr></table>	01	Oil	(Oil)	<p>estimates will be produced over time. EIA proved reserve estimates include reserves from which federal royalties will be received, as well as, reserves from which royalties will not be received due to various royalty relief policies.</p> <p>The model that MMS has created can be used to project the future production of the EIA proved reserve estimates assuming an exponential decline at a rate of the modeler's choice. The model also receives, as inputs, annual estimates of royalty free production from royalty relief. The annual production estimates of the proved reserves calculated by the model are then reduced by the royalty free annual volumes prior to the royalty calculations.</p> <p>Natural Gas Plant Liquids</p> <p>The Exposure Draft calls for the estimation of royalties from proved reserves of natural gas plant liquids (NGPL) along with royalties from proved reserve estimates of crude oil, lease condensate, and presumably dry natural gas. The EIA reports estimates of natural gas reserves in two different forms. One form is Dry Natural Gas which is the volume of natural gas after the natural gas liquids have been removed. The other form is Natural Gas, Wet After Lease Separation which is the volume of natural gas prior to the natural gas liquids being removed. Should dry gas proved reserves be used for the royalty estimates, NGPL proved reserve estimates should also be used to capture the entire hydrocarbon value. However, wet gas volumes and values are greater than dry gas volumes and values because of the additional content of NGPL in the wet gas. MMS prefers the use of the wet gas estimates because they replicate the form and the point in time when the royalty valuations are made. Further, MMS/OMM reservoir engineers and geoscientists are very experienced in dealing with and estimating reserves and production in terms of wet gas as all MMS/OMM datasets are in terms of wet gas. Finally, the use of dry gas and NGPL creates possibly insurmountable problems in properly</p>
01	Oil	(Oil)		

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
<p>02 Condensate (Lease Condensate)</p> <p>05 Drip or Scrubber Condensate (Lease Condensate)</p> <p>06 Inlet Scrubber (Lease Condensate)</p> <p>13 Fuel Oil (Oil)</p> <p>14 Oil Lost (Oil)</p> <p>20 Other Liquid Hydrocarbons (Oil)</p> <p>The Gas Category contains product codes of:</p> <p>03 Processed (Residue) Gas (Dry Gas)</p> <p>04 Unprocessed (Wet) Gas (Wet Gas)</p> <p>09 Nitrogen (Wet Gas)</p> <p>12 Flash Gas (Wet Gas)</p> <p>15 Fuel Gas (Wet Gas)</p> <p>16 Gas Lost - Flared or Vented (Wet Gas)</p> <p>39 Coal Bed Methane (Dry Gas)</p> <p>The NGL Category contains the product code of:</p> <p>07 Gas Plant Products</p>	<p>allocating reserves back to their source fields, affecting value estimations at the proper royalty rates, and in constructing production profiles. Adding values for NGPL to this would amount to a double counting of the values of NGPL. MMS has used only wet gas proved reserves estimates (and no estimated of NGPL) in its trial analysis and highly recommends this procedure for these calculations.</p> <p>Product Prices</p> <p>Of equal importance in the estimation of the present value of royalties to the production estimates are the estimates of future oil and gas prices. MMS-OMM recommends that independently generated and commonly available price estimates be used. The MMS-OMM already uses and is familiar with the OMB economic assumptions that are generated semi-annually for the President's Budget. For the purpose of the trial analysis performed, the oil and gas prices from the OMB's "Economic Assumptions for the 2008 Mid-Session Review" were employed.</p> <p>A minor limitation to those parameters is that the projections are only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary.</p> <p>Depending on the locations associated with the price parameters, the prices will have to be adjusted to approximate average wellhead prices for each OCS Region (GOM, Pacific, Alaska North Slope). Such an adjustment has two components, an adjustment to a regional landed average price, then a transportation allowance to a regional wellhead average price. The first adjustment to a regional landed average price will be conducted by observing the historical average relationship of the price series being considered (e.g., United States average wellhead natural gas price) to the average regional landed natural gas price (e.g., Henry Hub). From these observations, factors and/or trends in these</p>
<p>Where reported and paid separately, <u>dry gas had to be analyzed separately from wet gas</u>, and NGL's were also analyzed separately, averages computed and the totals then summed, in order to derive a more accurate estimate. This differs somewhat from the Exposure Draft, which reports only dry gas and NGL's. However, as a result of the field test, it is apparent that not only is this the reported information that is available, analyzing and computing each commodity category separately also produces a more accurate overall estimate. However, this is limited to the commodity categories reported in common between EIA and MRM. For purposes of the field study only, coal bed methane was added to onshore dry gas, as the rate and price were fairly comparable. But in practice, since proved reserve and estimated production</p>	

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<p>data are available from EIA, this commodity could be computed and reported separately.</p> <p>Commodity categories and units were at the common level between EIA and MMS:</p> <table border="0"> <tr> <td>Dry Gas</td><td>(mcf)</td></tr> <tr> <td>Wet Gas</td><td>(mcf)</td></tr> <tr> <td>NGL's</td><td>(bbl 42 us gal)</td></tr> <tr> <td>Oil</td><td>(bbl)</td></tr> <tr> <td>Lease Condensate</td><td>(bbl)</td></tr> </table> <p>Next, to compute the estimated beginning balance of the federal royalty share of the asset to capitalize, MMS CRB utilized the existing royalty reported data for sales months in calendar year 2005 which had been provided by MRM to aid in computing the estimated quantity, as it had already been refined and was available. This was done solely for illustrative purposes to obtain a beginning balance. In actual practice this unique scenario would not exist, where the EIA published data and the MRM reported royalty data would cover the exact same time frame for computing the averages. In practice, the MRM reported data used to compute the averages would be more current, and reflect more current volumes, prices and rates. It would be based upon the preceding 12 sales months royalties reported for which royalty production data is available, or July through June when measured at September 30 (please refer to pp. 12 in the ED).</p> <p>Average royalty rates were computed by dividing the total regional royalty value by the total regional sales value by commodity categories for sales months in calendar year 2005. Average unit prices were similarly derived by dividing the total regional sales value by the total regional sales volume. Then, the asset value was computed by simply multiplying average rate X average unit price</p>	Dry Gas	(mcf)	Wet Gas	(mcf)	NGL's	(bbl 42 us gal)	Oil	(bbl)	Lease Condensate	(bbl)	<p>price relationships can be deduced and applied to the price projections to result in projections of regional landed prices. Such relationships need to be studied in detail prior to "going live" with the present value estimates. For the purpose of the trial analysis performed, it was assumed that the OMB's average imported and domestic refiner's acquisition cost for oil and the average wellhead price for imported, inter-, and intra-State natural gas estimates would be equivalent to the average landed prices of oil and gas for each Region. The OMB's price projections are expressed in nominal terms.</p> <p>Transportation Allowances</p> <p>The second component of the price adjustment is the transportation allowances. Lessees pay royalties based on the value of their production at the wellhead. Since the price adjustment above resulted in a regional average landed price, these need to be converted to regional average wellhead prices by subtracting a regional average transportation allowance.</p> <p>One approach would be for MMS-MRM to determine the necessary average historical transportation allowances claimed by lessees on royalty bearing production for the previous 12 sales months. Such averages would be weighted by the volume of production using that allowance, would be by commodity, and for the GOM, would be by the royalty rate of the contributing leases. The assumption would then be that the resulting previous 12-month average transportation allowances would also apply to all future production within the same category. Because the price projections used are nominal values, the transportation allowances would be increased in the future with inflation.</p> <p>This method was employed in the trial analysis, though further study of the accuracy of this approach would be necessary prior to any official calculations.</p>
Dry Gas	(mcf)										
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<p>X estimated quantity for each region and commodity category. The totals were then summed to arrive at the total asset estimated value to capitalize.</p> <p>In deriving the averages, numerous factors had to be included, such as excluding royalty relief volumes and estimating the value of commodity received in kind and delivered to DOE to fill the Strategic Petroleum Reserve (SPR). For purposes of the study, since SPR royalty reports contain volumes but no value, the average rate and unit price computed for Gulf oil were imputed to the SPR volumes, and the value computed from these averages. In practice, this method could be used, or alternatively the volumes could be obtained from royalty reports, the value from the manual journals used to record the activity in the period, and the average rate and average unit price then computed. The summary calculations are presented in Illustration 1.</p>	<p>Discount and Inflation Rates</p> <p>As for product prices, MMS-OMM recommends that independently generated and commonly available discount and inflation rates be used in calculating the royalty present value. A public sector discount rate for the federal government should be readily available and applicable for this purpose. For the purpose of the trial analysis, MMS assumed a discount rate equal to the federal government's interest rate paid on its long-term borrowing as the discount rate. OMB's projection of the 30-year Treasury Bill rate was used. For inflation, MMS assumed OMB's projection of the GDP Price Index for the trial analysis.</p> <p>As was the case for OMB's oil and gas price projections, projections of these parameters by OMB are also only for 10 years into the future. An extrapolation of out-year trends in the projections has been made to extend the price profiles as long as necessary.</p> <p>Present Value Calculations</p> <p>For all federal offshore areas, MMS proposes the use of the following method to estimate the present value of future federal royalties from proved reserves:</p> <ol style="list-style-type: none"> 1) By federal OCS Region, project production of DOE-EIA proved oil/condensate, and wet natural gas reserves estimates over time until depleted, 2) In GOM, also project separately for one-sixth and one eighth royalty rate leases (use water depth subsets of >400m and <400m as proxy), 3) Where applicable, determine adjustments needed to reflect projected royalty free production from royalty relief leases and modify as appropriate the total projections above, 4) Calculate future regional landed prices from price projection

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	<p>(OMB or other) assigned by FASAB using historical price relationships to make further adjustments,</p> <p>5) Calculate future wellhead landed prices from regional landed prices using average actual transportation allowances claimed for the previous 12-month period.</p> <p>6) For production for each Regional commodity by royalty rate, calculate annual royalties as follows:</p> <p><i>(Annual Production less adjustments for Annual Royalty Free Production) * (Annual Regional Landed Price – Average Transportation Allowance) * Royalty Rate</i></p> <p>7) For a given vector of calculated future annual royalty estimates, determine the present value of the royalty revenue stream assuming the discount rate (OMB 30-year Treasury Bill or other) assigned by FASAB.</p> <p><u>Trial Analysis</u></p> <p>Using the above methodology, MMS constructed a model and completed a trial calculation for the federal offshore areas assuming that the effective date of the royalty valuation would be October 1, 2007. MMS used its model and made separate calculations of the present value of proved reserves for the relevant categories pertaining to the federal Outer Continental Shelf. Presented below are the categories and resulting present value estimates:</p> <table border="1" data-bbox="1050 1166 1885 1412"> <thead> <tr> <th colspan="2">PV of Future Federal OCS Royalty Receipts - Eff 10/1/2007 (\$MM)</th></tr> </thead> <tbody> <tr> <td>GOM One-Sixth Royalty Oil/Condensate</td><td>\$ 5,702.35</td></tr> <tr> <td>GOM One-Eighth Royalty Oil/Condensate</td><td>\$20,737.99</td></tr> <tr> <td>GOM One-Sixth Royalty Wet Gas</td><td>\$ 8,923.55</td></tr> <tr> <td>GOM One-Eighth Royalty Wet Gas</td><td>\$ 4,198.31</td></tr> <tr> <td>Pacific Region Oil/Condensate</td><td>\$ 1,868.62</td></tr> <tr> <td>Pacific Region Wet Gas</td><td>\$ 409.59</td></tr> </tbody> </table>	PV of Future Federal OCS Royalty Receipts - Eff 10/1/2007 (\$MM)		GOM One-Sixth Royalty Oil/Condensate	\$ 5,702.35	GOM One-Eighth Royalty Oil/Condensate	\$20,737.99	GOM One-Sixth Royalty Wet Gas	\$ 8,923.55	GOM One-Eighth Royalty Wet Gas	\$ 4,198.31	Pacific Region Oil/Condensate	\$ 1,868.62	Pacific Region Wet Gas	\$ 409.59
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<p>The initial value of estimated petroleum royalties is a hypothetical number used for illustrative purposes only. The hypothetical initial</p>	<ul style="list-style-type: none"> • 85% of the productive wells begin production in the first year • 10% of the productive wells begin production in the second year • 4% of the productive wells begin production in the third year • 1% of the productive wells begin production in the fourth year • Average oil well produces 7,300 barrels per year or 20 barrels per day • Decrease of 10% per year for oil production • Decrease of 10% per year for gas production • Average gas well produces 80,000 MCF per year or 219 MCF per day • APDs processed in 2008 - 2011 are set at 11,500 and then start a slow decline of 500 APDs per year. <p>Once yearly production estimates were established they were subtracted from the federal proved reserves until the proved reserves were zero. A similar present value method was applied to onshore quantities. A yearly estimated price for oil, natural gas and natural gas liquids was used based on OMB estimates. Since the OMB estimates only went out for ten years, prices were estimated based on the trend of the OMB estimates after that. A royalty rate based on historic data from MMS was used to estimate the royalty rate. The data from MMS on the royalty rate appeared to be constant, so no change in the royalty rate was made for each year. A standard discount rate was used to bring future dollars back to today dollars.</p> <p>The estimated yearly production was multiplied by estimated average yearly price, the royalty rate and the discount rate for that year. All of these totals were added together to come up with the estimated value of each commodity (oil, natural gas and natural gas liquids). These total were added together to come up with a estimated total value of the federal onshore oil and gas proved reserves, which was \$23,088.64.</p> <p>The initial value of estimated petroleum royalties is a hypothetical number used for illustrative purposes only. The hypothetical initial</p>

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
<p>value of estimated petroleum royalties based on the methodologies described above is \$112,380,231,231. The illustrative pro forma transaction to record the initial value of the federal government's estimated petroleum royalties and related liability is presented below. The asset's value represents the effective average royalty share of the federal oil and gas resources classified as "proved reserves." The related liability represents the effective average royalty share of the federal oil and gas resources classified as "proved reserves" designated to be distributed to others, i.e., the states, the general fund of the U.S. Treasury and other federal component entities, not including the component entity responsible for collecting royalties. The proposed treatment of distribution of revenue to others creates a federal and a non-federal liability for the component entity responsible for collecting royalties.</p> <p>The cumulative effect of adopting this accounting standard would be reported as a "change in accounting principle" in accordance with SFFAS 21, <i>Reporting Corrections of Errors and Changes in Accounting Principles</i>. The adjustment would be made to the beginning net position on the component entity responsible for collecting royalties Statement of Changes in Net Position for the period the change is made and the other federal component entities for their allocable share of the related asset. To obtain the value of the adjustment, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the component entity responsible for collecting royalties. For this illustration, one percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting royalties based on the average distribution for 2005.³ To record the related liabilities the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.⁴ For this illustration, 84 percent was</p>	<p>value of estimated petroleum royalties based on the PV methodology described below for offshore is \$41,840,410,000, and for onshore is \$23,088,640,000, for a total of \$64,929,050,000. The illustrative pro forma transaction to record the initial value of the federal government's estimated petroleum royalties and related liability is presented below. The asset's value represents the estimated royalty share of the federal oil and gas resources classified as "proved reserves." The related liability represents the estimated royalty share of the federal oil and gas resources classified as "proved reserves" designated to be distributed to others, i.e., the states, the general fund of the U.S. Treasury and other federal component entities, not including the component entity responsible for collecting royalties. The proposed treatment of distribution of revenue to others creates a federal and a non-federal liability for the component entity responsible for collecting royalties.</p> <p>The cumulative effect of adopting this accounting standard would be reported as a "change in accounting principle" in accordance with SFFAS 21, <i>Reporting Corrections of Errors and Changes in Accounting Principles</i>. The adjustment would be made to the beginning net position on the component entity responsible for collecting royalties Statement of Changes in Net Position for the period the change is made and the other federal component entities for their allocable share of the related asset. To obtain the value of the adjustment, the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the component entity responsible for collecting royalties. For this illustration, one percent was used as the average annual share of the revenue distributed to the component entity responsible for collecting royalties based on the average distribution for 2005.⁶ To record the related liabilities the total estimated petroleum royalties is multiplied by the average share of the revenue distributed to the states. For this illustration, 15 percent was used as an average annual share of the revenue distributed to the States based on the average distribution for 2005.⁷ For this illustration, 84 percent was used as an average annual share of the revenue distributed to other</p>

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
<p>other federal component entities based on the average distribution for 2005.⁵ These calculations are presented below:</p> <p>$\\$112,380,231,231 \times .01 = \\$1,123,802,312$</p> <p>$\\$112,380,231,231 \times .84 = \\$94,399,394,234$</p> <p>$\\$112,380,231,231 \times .15 = \\$16,857,034,685$</p> <p>Dr Estimated Petroleum Royalties 112,380,231,231</p> <p>Cr PPA: Change In Acct Principle 1,123,802,312</p> <p>Cr Liability for Rev Distr to Others-Federal 94,399,394,234</p> <p>Cr Liability for Rev Distr to States-Non-Fed 16,857,034,685</p> <p><i>To record initial value of estimated petroleum royalties due to change in accounting principle, the related liabilities to state and local governments, and the related liabilities to other Federal component entities. (The 1% expected to be retained by the entity responsible for making royalty collections increases its net position.)</i></p>	<p>These calculations are presented below:</p> <p>$\\$64,929,050,000 \times .01 = \\$649,290,500$</p> <p>$\\$64,929,050,000 \times .84 = \\$54,540,402,000$</p> <p>$\\$64,929,050,000 \times .15 = \\$9,739,357,000$</p> <p>Dr Estimated Petroleum Royalties 64,929,050,000</p> <p>Cr PPA: Change In Acct Principle 649,290,500</p> <p>Cr Liability for Rev Distr to Others-Federal 54,540,402,000</p> <p>Cr Liability for Rev Distr to States-Non-Fed 9,739,357,000</p> <p><i>To record initial value of estimated petroleum royalties due to change in accounting principle, the related liabilities to state and local governments, and the related liabilities to other federal component entities. (The 1% expected to be retained by the entity responsible for making royalty collections increases its net position.)</i></p>
<p>2. Record payment of the one-fifth bonus bid amounts.</p> <p>(same entry in all three – no differences)</p>	
<p>Dr Fund Balance with Treasury 1,540,000</p> <p>Cr Unearned Revenue 1,540,000</p> <p><i>To record collection of the one-fifth bonus bids for the four bonus bids.</i></p>	<p>same</p>
<p>3. Record remaining payment by the successful bidder and the annual rental fee and the related liability for revenue distributions to others.</p> <p>(same entries in all three – no differences)</p>	

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
<p>Dr Unearned Revenue 400,000 Dr Fund Balance with Treasury 1,960,000 Cr Revenue from Rent 360,000 Cr Revenue from Bonus Bid 2,000,000</p> <p><i>To record remaining bonus payment and the annual rental fee by the successful bidder, and associated liability and nominal accounts, less MMS 1% (23,600).</i></p> <p style="text-align: center;">$\\$2,360,000 \times .15 = \\$354,000$ $\\$2,360,000 \times .84 = \\$1,982,400$</p> <p>Dr Rev Desgn for Others - Non-Fed⁹ 354,000 Dr Transfers-Out 1,982,400 Cr Liability for Rev Distr to Others-Fed 1,982,400 Cr Liability for Rev Distr to States-Non-Fed 354,000</p> <p><i>To record the related increase in the liability for the future revenue distributions to others.</i></p> <p><u><i>Other federal component entity entry:</i></u></p> <p>Dr Accounts Receivable 1,982,400 Cr Transfer-In 1,982,400</p> <p><i>To record the related accrual of a transfer-in and a reduction in the long-term A/R.</i></p>	<p>same</p>
<p>4. Receive the annual rental fee from pre-existing leases and record the related liability for revenue distributions to others. (same entries in all three – no differences)</p>	
<p>Dr Fund Balance with Treasury 239,501,681 Cr Revenue from Rent 239,501,681</p>	<p>same</p>

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
<p><i>To record rental payments on leases for the year.</i></p> <p style="text-align: right;">\$239,501,681 X .15 = \$35,925,252</p> <p style="text-align: right;">239,501,681 X .84 = \$201,181,412</p> <p>Dr Rev Design for Others – Non-Fed 35,925,252</p> <p>Dr Transfers-Out 201,181,412</p> <p style="padding-left: 40px;">Cr Liability for Rev Distr to Others-Fed 201,181,412</p> <p style="padding-left: 40px;">Cr Liability for Rev Distr to States-Non-Fed 35,925,252</p> <p><i>To record the related increase in the liability for the future revenue distributions to others.</i></p> <p><u>Other federal component entity entry:</u></p> <p>Dr Accounts Receivable 201,181,412</p> <p style="padding-left: 40px;">Cr Transfer-In 201,181,412</p> <p><i>To record the related accrual of a transfer-in and a reduction in the long-term A/R.</i></p>	
<p>5. Refund unsuccessful bidders' bonus bid deposits.</p> <p>(same entries in all three – no differences)</p>	
<p>Dr Unearned Revenue 1,140,000</p> <p style="padding-left: 40px;">Cr Fund Balance with Treasury 1,140,000</p> <p><i>To record refund of losing bonus bids.</i></p>	<p>same</p>
<p>6. Record earned royalty revenue and depletion expense.</p> <p>(same entries in both field tests; amount different in ED - \$4,416,252,801)</p>	

ED	PV
<p>The ED states that, <i>“Earned royalty revenue should be recognized as exchange revenue by the component entity that is responsible for collecting the royalties. At the same time, an amount equal to the royalty collections should be recognized as depletion expense; and, the value of estimated petroleum reserves should be reduced by the depletion expense amount. Sales value and royalty payment information are due on or before the last of the month following the month the oil or gas product from Federal oil and gas resources was sold or removed from the lease. For example, oil or gas sold in June must be reported by July 31, the end of the following month.”</i></p> <p>There are extensive issues discussed below around the many components of revenue recognized by the collecting entity, the relationship of that revenue to depletion expense, and the present or future ability to obtain information at the level of detail presented in the ED. This is a significant set of issues that we believe must be addressed before the ED is finalized.</p> <p>The ED proposes to base depletion expense upon oil & gas ‘royalty revenue earned’ for the fiscal year (pp. 23, and Appendix C, entry #6), and is silent regarding what components would comprise this value, except that pp. 23 refers to ‘royalties from the production’ of proved reserves. This introduces many complexities, including whether or how to include estimates such as the ‘royalty accrual’ (discussed below), and the relationship between revenue recorded in the current fiscal year for royalty reporting adjustments made to prior years and current year depletion expense.</p> <p>Revenue earned by the collecting entity generally consists of amounts reported or billed, cash for which no royalty report has been received (unmatched cash), and amounts accrued as</p>	<p>same</p>

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
<p>estimates. There is not a simple means at this time to obtain detail which reconciles to the general ledger and financial statements, of all components of earned revenue specifically related to oil and gas and more specifically related to offshore vs. onshore leases.</p> <p><u>Earned Revenue Based Upon Royalty Reports; Royalty Adjustments to Prior Periods:</u></p> <p>In addition to current royalty amounts, MMS records earned revenue in the current period for the sum of both positive and negative amounts resulting from upward or downward adjustments to prior royalty reporting, related to previous months when the commodity had been either sold or removed from the lease (sales months). This is a standard business process in oil and gas industry reporting, resulting from the receipt of subsequent information related to previous reporting periods that was unknown when the compulsory reporting was legally due, such as revised pipeline statements. These adjustments frequently cross monthly, quarterly, and fiscal year boundaries, can be large amounts, and are routine.</p> <p>If depletion expense is linked across the board with overall revenue earned in the current year, then it must be understood that it would be at least partially based on revenue earned in the current year that is related to adjustments to prior periods falling outside the fiscal year. Therefore, the asset would be depleted in the current year based upon activity that does not actually reflect true depletion in the actual year.</p> <p>If depletion expense were alternatively based upon revenue earned for oil & gas royalty reports related to current year production only, to most closely reflect the actual asset depletion in the current year, it would be applicable to only the sales months falling within the fiscal year. This would exclude prior period adjustments to royalty reporting that would be deemed unrelated to</p>	

ED	PV
<p>depletion in the current year.</p> <p>However, complete royalty reporting covering production in the current fiscal year measured at 9/30 can only be ascertained through August, which covers actual reported royalty production through June (for which delayed reporting would not be due until August if a paid estimate were in place). In other words, only 9 months of complete sales month (production) data within a given fiscal year are available at 9/30 if basing 'revenue earned' and depletion expense only on current fiscal year sales months; October through June. Clearly, this would not present a complete picture of current year asset depletion, because it would not even include a full 12 months of royalty reporting.</p> <p>The recommended alternative is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end; July through June (received through August, fully available in September). This would preclude the need to include estimates in the depletion calculations (discussed below), and would represent a realistic value of true asset depletion based on actual royalty reporting. Revenue earned would not be a perfect match in the fiscal year, but in this case it should not, because depletion in the current year should not be linked to prior adjustments not related to the current year. To do otherwise would include prior period adjustments not related to depletion in the year, and would involve complex and extensive inclusion of current year estimates that also include prior period adjustments. This method would likely yield a more accurate picture of current asset depletion over a year span. This method would also provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, onshore vs. offshore and other necessary details.</p>	

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
<p>Another alternative would be to record depletion based solely upon all royalty lines received and accepted during the fiscal year, excluding all accruals and regardless of sales month. Again, revenue earned would not be a perfect match in the fiscal year, because accruals would be excluded. But including all lines accepted in a year would eliminate the need to include complex and extensive current year-end estimates for which disclosure detail is not available (see discussion below) because actuals over a 12 month span would be fully included. This method would, however, include all adjustments to prior reporting received in the current fiscal year, and while it may provide a closer tie to actual revenue reported in the financial statements, it would not be as fair a measure of asset depletion in the year. This method, like the recommended method above, would provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, and other necessary details.</p> <p><u>Earned Revenue; Document Level Royalty Reporting Accruals vs. Line Level Royalty Detail:</u></p> <p>When a royalty document is received, it usually includes numerous individual 'lines' of reporting. Each line contains specific detail about the royalty, such as the individual lease number, sales month and product code. If even one line of the royalty document passes edits and accepts in the royalty accounting system (MRMSS), then revenue is recorded for the full 'document calculated total'. If all lines reject, then a manual accrual is made for the full 'document calculated total'. Priority is placed on clearing rejected lines as quickly as possible, generally in the month following receipt. In subsequent periods, as the previously rejected royalty lines are corrected and accept in the MRMSS, they do not give rise to revenue, as it was already properly accrued when the document was first received.</p>	

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
<p>As you can see, the detail required in the ED for 'earned revenue' by oil or gas and onshore vs. offshore is not readily obtainable for this portion of the population (rejected lines in the last month of the year). For purposes of the field study, CRB undertook an initial effort to ascertain in a 1-month period, the detail related to line level royalty revenue earned by oil or gas and onshore vs. offshore. In instances where the doc calc total giving rise to revenue in the period did not equal the sum of the accepted lines in the system, CRB developed a method to allocate (estimate) earned revenue to detail associated with existing lines. This identified a significant problem in our ability to report accurately on the detail associated with 'earned revenue' based on current month royalty reporting. In many cases, the revenue was allocated to oil or gas based upon an estimate that may or may not be correct, and which may not prove to be correct in subsequent periods when the rejected lines are corrected and accept in the system. This issue further supports the premise that depletion be based solely upon accepted royalty reporting lines for given sales months, as presented above, and not on accruals and estimates.</p> <p><u>Earned Revenue; Estimates and Manual Accruals:</u> When examining 'earned revenue' and its relationship to asset depletion, CRB performed an extensive analysis for the field study, of estimates and manual accruals related to current period royalty revenue.</p> <p>MMS records numerous manual accruals to fairly present assets, liabilities and revenue in the financial statements. One such entry is the 'royalty accrual', a large accrual that represents estimated production in the current month for oil, gas and solid minerals, where the royalty reports are not yet received. The royalty accrual is not computed based on sales month (production month), but</p>	

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
<p>rather upon when the royalty report was received. It is computed based on a 12-month average of previous royalty reports received. Revenue recognition for royalty is consistent therefore, because prior period adjustments to previous royalty reporting are treated as current year revenue, upward or downward, and factored into the current period royalty accrual. The royalty accrual is subject to extensive year-end audit review, and a large subsequent adjustment may be required annually, later in the financial reporting process (early November). If included in the revenue matched with depletion expense, this would also then, require that the proved reserves asset be adjusted accordingly, and would impact materially, all allocated downstream recipients as well.</p> <p>The royalty accrual is required to be performed fairly quickly, at the high level, to meet accelerated financial reporting objectives. It includes adjustments to prior reporting periods, and it does not contain the detail required in the ED, to break out oil vs. gas and onshore vs. offshore. Of course, a rough estimation method could always be developed, but its accuracy and validity when compared to subsequent actual information could potentially prove to be incorrect.</p> <p>Another significant manual accrual involves unmatched cash for which no royalty report has been received at the end of the reporting period. This occurs monthly, and this large unmatched cash balance can not accurately be linked to oil or gas, onshore or offshore. In some instances, large compliance settlement amounts may be included in the cash balance, not related to current year royalties. Large amounts could be related to interest payments. It would be incorrect to allocate current year depletion to unmatched amounts that may not be related. Also, this unmatched cash, when applied to subsequent royalty reports, will likely relate to adjustments to prior reporting, and also not bear a</p>	

ED	PV
<p>relationship to current year asset depletion.</p> <p>Previous discussions with FASAB Staff indicated that in order to provide matching of royalty revenue earned in the fiscal year, the royalty accrual would be included in the 'revenue earned' that would be offset by depletion expense, because the accrual estimates production in the current month for which royalty reports will not be yet be received. Also, it was discussed that revenue recognition overall should remain consistent, and that revenue earned in the fiscal year, regardless of sales (production) month and subsequent adjustments, would still apply. Accordingly, the text in pp. #23 and throughout the Statement was going to be revised to include, "Royalties received and accrued..."</p> <p>However, upon analysis as a result of the field test study, it is apparent that the degree of detail required to be estimated, allocated and reported is very extensive, labor intensive, includes adjustments to prior period reporting which may not relate to current period asset depletion at all, and poses significant risks to meeting audit and accelerated financial reporting objectives. Again, including these and other estimates, by default, includes adjustments to prior reporting, or other activity not necessarily related to actual current period asset depletion. The degree of detail for disclosure required in the ED would not be readily available from these estimates, and would have to be extensively estimated. And the inclusion of these estimates would likely not yield a better, and perhaps a worse, measure of actual asset depletion in the year, as opposed to the recommended sales month method described above. For the many complex accruals currently performed by MMS, estimation methods would have to be developed to allocate some portion of the earned revenue to oil and gas, and then of that subset, to onshore vs. offshore.</p>	

ED	PV
<p>For purposes of this field test study, revenue overall is presented in aggregate, includes estimates and is based upon royalty reporting lines received and accepted in the fiscal year, regardless of sales months, to tie with current practices. This is done to illustrate the many estimates performed, their relationship to earned revenue, and to explain why the detail required in the ED can not currently be provided. However, it is not the recommended method for deriving depletion expense. Also, disclosures were not attempted.</p> <p>As we have discussed, estimations pose significant challenges to MMS' ability to produce adequate detail in the required disclosures regarding revenue earned by oil and gas and onshore vs. offshore categories. It currently could not be readily done with existing resources or information. Each line of each component of earned revenue would have to be carefully analyzed, an allocation method developed for oil and gas and onshore vs. offshore, and would be an extensive and labor intensive process. A sophisticated system report and queries could be developed to help provide some of this degree of detail, but it would not resolve issues around allocations of estimates, and timing would be crucial, as reconciliations and adjusting entries would need to be made quickly, to meet accelerated financial reporting deadlines, and to pass audit requirements.</p> <p>The matrix in Illustration 3 presents some of the key components of 'earned royalty revenue' presently recorded by MMS, and demonstrates how the earned royalty revenue value was estimated for the illustrative pro forma entries. It must be noted that in actual practice, the previous year-end estimate would be reversed in the subsequent year, so that actual revenue recorded in any given year related to estimates would essentially reflect the change associated with those estimates over the year. In this example, for the study, the full values were presented, to give the reader a</p>	

ED	PV
<p>general idea of the relative sizes of the estimates under discussion.</p> <p>Again, the primary concerns related to recording depletion expense based on revenue which includes estimates revolve around mismatching unrelated portions of estimates with actual asset depletion, potential material audit findings and a potential inability to meet accelerated financial reporting objectives.</p> <p>As an aside, if using the recommended sales month method described above for ascertaining the amount of depletion to record in a fiscal year, then the actual royalty value for oil and gas reported to MMS was approximately \$9.2 billion for the most recent sales months available when performing the field test, June 2006 through May 2007, obtained in mid-August 2007.</p> <p>To restate, some of the key concerns around recording depletion expense based upon the sum of current year royalty reports and estimates include:</p> <ul style="list-style-type: none"> ✦ Revenue and depletion expense would be mismatched due to prior period adjustments not related to current period depletion captured as revenue in the current year. ✦ The revenue estimate including accruals would also include estimates of production anticipated through year-end, and estimates of unmatched cash with estimates sub-allocated to oil & gas, and then sub-allocated to onshore vs. offshore. The estimated allocations will likely be later found to be incorrect. Also, the estimates include adjustments to prior periods, not attributable to depletion in the current period. ✦ Each estimate is already complex to derive, and currently does not include a method for allocating to oil or gas, or onshore vs. offshore. ✦ Revising each estimate accordingly will decrease the likelihood 	

ED	PV
<p>of meeting accelerated financial reporting objectives, and will increase the likelihood of audit failures, and their severity based on materiality.</p> <p>⊕ Estimates and subsequent changes to estimates will impact the asset value through depletion expense, and so, all designated downstream recipients.</p> <p>⊕ Estimates measured against subsequent actuals at fiscal year end will likely result in material adjustments near the close of the annual financial audit process in early November, and also require adjustment by designated downstream recipients.</p> <p>For illustrative purposes, the hypothetical numbers previously discussed are presented. The estimated royalty revenue earned and accrued for the fiscal year for offshore and onshore rental leases estimated allocated to oil and gas only was used in this calculation. The estimated royalty revenue earned and accrued during the fiscal year for offshore and onshore leases was roughly estimated to be \$11,519,015,047. <u>[This amount was requested to be separated into offshore and onshore amounts in the ED.]</u></p> <p>The following entries are recorded by the component entity responsible for collecting royalties.</p> <p>Dr AR (Billed and Unbilled Accrued) 11,519,015,047 Cr Rev from Royalties for Fed Reserves 11,519,015,047</p> <p><i>To record earned royalty revenue.</i></p> <p>Dr Oil and Gas Depletion Expense 11,519,015,047 Cr Estimated Petroleum Royalties 11,519,015,047</p> <p><i>To record depletion expense for federal oil and gas resources.</i></p>	

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
7. Record collection of royalty revenue. (same entries in both field tests; amount different in ED - \$4,048,231,734)	
Dr Fund Balance with Treasury 10,048,231,734 Cr Accounts Receivable 10,048,231,734 <i>To record collection of royalty revenue.</i>	same
8. Record distribution of bonus bid, rent, and royalty collections and the reduction in the liability for the revenue distributed to others. (same entries in both field tests; amount different in ED - \$4,247,192,481 for first and \$3,603,678,469 for second)	
$\$10,290,093,415 \times .15 = \$1,543,514,012$ $\$10,290,093,415 \times .84 = \$8,643,678,469$ Dr Liability for Rev Distr to Others-Fed 8,643,678,469 Dr Liability for Rev Distr to States-Non-Fed 1,543,514,012 Cr Fund Balance with Treasury 10,187,192,481 <i>To record distribution of bonus bid, rent, and royalty revenue collections and the reduction in liabilities for revenue distribution to others.</i> <u>Other federal entity entry:</u> Dr Fund Balance with Treasury 8,643,678,469 Cr Accounts Receivable 8,643,678,469 <i>To increase the fund balance with treasury and reduce the accounts receivable in relation to distributions received.</i>	same
9. Disclose rights to future royalty streams identified for sale.	

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

ED	PV
Key subject matter experts have indicated that this scenario is very highly unlikely. Because such extensive analysis and work was required to satisfy other aspects of the field study, this valuation was not revised from the original proposal in the ED.	
10. Record sale of future royalty streams identified for sale and the related change in the liability for revenue distributions to others. Key subject matter experts have indicated that this scenario is very highly unlikely. Because such extensive analysis and work was required to satisfy other aspects of the field study, this valuation was not revised from the original proposal in the ED.	

Illustration 1

Summary: Calculations of Estimated
Proved Reserves

Federal Offshore Royalties Reported

Calendar Year 2005 Sales Months as of September 4, 2007

Categories Consolidated - Offshore

		Volume	Value	Royalty Value	Calc Royalty Rate	Calc Unit Price
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	1,634,243,775.24	12,891,342,243.25	1,874,938,867.11	0.145442	7.89
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	1,396,328,369.82	9,594,581,770.75	1,469,886,320.24	0.153200	6.87
	Gas Total	3,030,572,145.06	22,485,924,014.00	3,344,825,187.35	0.148752	7.42
NGL (gal)	Gas Plant Products (gal)	2,106,307,734.15	1,611,579,527.38	135,731,752.01	0.084223	0.77
NGL (bbl 42 gal)	Gas Plant Products Total (bbl 42 gal)	50,150,184.15	1,611,579,527.38	135,731,752.01	0.084223	32.14
Oil (bbl)		331,872,511.54	15,603,826,996.48	2,133,366,086.08	0.136721	47.02
Condensate (bbl)		39,613,036.74	1,291,839,143.91	195,812,132.70	0.151576	32.61
Oil & Cond (bbl)	Oil & Condensate Total	371,485,548.28	16,895,666,140.39	2,329,178,218.78	0.137857	45.48

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

Calculated Estimated Proved Reserves Under Federal Domain - Federal Royalty Share, as of 9/4/2007 - Offshore

		Onshore Est Proved Reserves	Offshore Est Proved Reserves	Total Est Proved Reserves	Est Asset Val (Avg Rate X Avg Price X Est Quantity)
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	-	18,604,000,000.00	18,604,000,000.00	21,344,038,883.42
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	-	19,040,000,000.00	19,040,000,000.00	20,043,018,635.35
	Gas Total	-	37,644,000,000.00	37,644,000,000.00	41,387,057,518.77
NGL (gal)	Gas Plant Products (gal)				
NGL (bbl 42 gal)	Gas Plant Prod Total (bbl 42 gal)	-	740,000,000.00	740,000,000.00	2,002,814,111.19
Oil (bbl)		-	4,758,000,000.00	4,758,000,000.00	30,585,708,320.54
Condensate (bbl)		-	293,000,000.00	293,000,000.00	1,448,335,184.64
Oil & Cond (bbl)	Oil & Condensate Total	-	5,051,000,000.00	5,051,000,000.00	32,034,043,505.19

Total Est Proved Reserves, Asset Value - Fed Royalty Share - CY 2005 Sales Months - Offshore

75,423,915,135.15

**Federal Onshore Royalties Reported
Calendar Year 2005 Sales Months as of September 4, 2007
Categories Consolidated - Onshore**

		Volume	Value	Royalty Value	Calc Royalty Rate	Calc Unit Price
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	1,146,151,633.04	7,426,469,521.60	838,167,362.52	0.112862	6.48
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	1,467,970,348.00	10,602,363,010.95	1,283,204,061.34	0.121030	7.22
	Gas Total	2,614,121,981.04	18,028,832,532.55	2,121,371,423.86	0.117665	6.90
NGL (gal)	Gas Plant Products (gal)	1,593,967,707.03	1,286,266,838.18	126,132,310.29	0.098061	0.81
NGL (bbl 42 gal)	Gas Plant Prod Total (bbl 42 gal)	37,951,612.07	1,286,266,838.18	126,132,310.29	0.098061	33.89
Oil (bbl)		86,644,381.56	4,304,809,820.77	379,491,776.77	0.088155	49.68
Condensate (bbl)		10,335,920.75	566,071,089.71	69,487,330.46	0.122754	54.77
Oil & Cond (bbl)	Oil & Condensate Total	96,980,302.31	4,870,880,910.48	448,979,107.23	0.092176	50.23

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

Calculated Estimated Proved Reserves Under Federal Domain - Federal Royalty Share, as of 9/4/2007

- Onshore

		Onshore Est Proved Reserves	Offshore Est Proved Reserves	Total Est Proved Reserves	Est Asset Val (Avg Rate X Avg Price X Est Quantity)
Dry Gas (mcf)	Processed (Residue) Gas (mcf)	15,227,904,771.19	-	15,227,904,771.19	11,135,989,698.78
Wet Gas (mcf)	Unprocessed (Wet) Gas (mcf)	19,425,200,893.36	-	19,425,200,893.36	16,980,245,352.14
	Gas Total	34,653,105,664.55	-	34,653,105,664.55	28,116,235,050.92
NGL (gal)	Gas Plant Products (gal)				
NGL (bbl 42 gal)	Gas Plant Prod Total (bbl 42 gal)	470,294,072.95	-	470,294,072.95	1,563,023,932.26
Oil (bbl)		1,480,091,280.44	-	1,480,091,280.44	6,482,618,488.16
Condensate (bbl)		118,169,090.91	-	118,169,090.91	794,438,625.14
Oil & Cond (bbl)	Oil & Condensate Total	1,598,260,371.35	-	1,598,260,371.35	7,277,057,113.30

Total Est Proved Reserves, Asset Value Est - Fed Royalty Share - CY 2005 Sales Months - Onshore

36,956,316,096.47

Total Estimated Proved Reserves, Asset Value Estimate - CY 2005 Sales Months

112,380,231,231.63

Illustration 2

Fiscal Year	Oil Price ¹ (\$/bbl)	Gas Price ² (\$/mcf)	Discount Rate ³ (%/Year)	Inflation Rate ⁴ (% Change Yr/Yr)
2006	59.94	7.45	4.85	3.1
2007	56.57	6.59	4.87	2.7
2008	63.26	7.70	5.18	2.4
2009	64.09	7.64	5.33	2.2
2010	63.12	7.40	5.48	2.0
2011	62.29	7.18	5.60	2.0
2012	61.80	7.09	5.61	2.0
2013	61.59	7.23	5.61	2.0
2014	61.97	7.38	5.61	2.0
2015	63.21	7.52	5.61	2.0
2016	64.47	7.68	5.61	2.0
2017	65.76	7.83	5.61	2.0
Annual Rate of Increase Thereafter	2.0%	2.0%	0.0%	2.0%
¹ Average Imported and Domestic Refiner's Acquisition Cost				
² Average Wellhead Price for Imported, Inter-, and Intra-State Natural Gas				
³ 30-Year Treasury Bills, Notes, and Bond, Bond Equivalent Rate				
⁴ Gross Domestic Product Price Index				

Illustration 3

Analysis of Components - Oil & Gas Revenue Earned - Entry #6, FASAB ED

Amounts are representational and illustrative only, to present basic concepts, and are not necessarily based on final or actual numbers

Total Royalty Report Line Level Data Received in Period (Royalty Value Less Allowances - RVLA)	10,731,532,649
Royalty line amounts that do not give rise to revenue by collecting entity in period	
Document calculated total equals zero (non-value related adjustments)	246,825,251
No system receivable created, such as for Indian direct pay or Strategic Petroleum Reserve (SPR)	789,559,441
Royalty documents accepted in prior periods where previously rejected lines now accept	17,170,452
Total Royalty Line Amounts That Do Not Give Rise to Revenue by Collecting Entity in Period	1,053,555,144
Revenue From Royalty Lines - Other (Currently Reported in 'Rents and Royalties')	5,333,009
Remainder - Royalty Lines Giving Rise to Revenue Received in Fiscal Year, Attributable to Oil & Gas	9,672,644,496
Accrued Revenue and Estimates - O&G (Illustrative Ending Balances Only - Revenue would be recorded for change in accruals)	
Estimated Portion of Year-End Royalty Accrual Estimating Current Month Production, Oil & Gas	760,179,551
Year-End SPR Accrual Estimating Current Month Production Delivered to DOE, Oil Only	105,216,449
Annual Actual Revenue for Oil Taken In Kind to Fill Strategic Petroleum Reserve (SPR)	200,974,551
Other Invoices In Lieu of Royalty Reports Presumed to be Related to Oil and Gas Royalties	30,000,000
Estimated Royalty Portion of Enforcement Settlements if Related to Current Year - Oil & Gas	50,000,000
Estimated Portion of Numerous Other Revenue Accruals Estimated Allocated to Oil & Gas	200,000,000
Estimated Portion of Unmatched Cash Revenue - No Royalty Report – Allocated to Oil & Gas	500,000,000
Total of Accrued Revenue and Estimates To Be Estimated Allocated to Oil and Gas	1,846,370,551
Total Estimated Royalty Related Revenue and Depletion Expense, Oil & Gas, Fiscal Year 20XX	11,519,015,047

Tab F-2 – Comparison of ED to Field Test Questionnaire Responses

Other Revenue - Non-CY Oil & Gas Royalty

Revenue from Onshore lease sale bonus and 1st year rents (does not tie to pro forma entries – informational only)	286,344,000
Revenue from Offshore lease sale bonus and 1st year rents (does not tie to pro forma entries – informational only)	387,689,000
Revenue from PY Settlements including Civil Penalties and Interest (Currently reported in 'Rents and Royalties')	80,000,000
Revenue from Royalties - Other Commodities i.e. Solid Minerals (Currently reported in 'Rents and Royalties')	615,752,400
Revenue from Late Payment Interest (Currently reported in 'Rents and Royalties')	60,000,000
Other Commodity Related Miscellaneous Revenue Including Compliance (Currently reported in 'Rents and Royalties')	12,000,000
Total Other Revenue - Non-CY Oil & Gas Royalty	1,441,785,400
Total Revenue Reported on Fiscal Year 20XX Statement of Custodial Activity	12,960,800,447

Additional Comments

General: Additional nominal account entries would be made by the collecting entity, to track and report on greater detail than is presented in the ED. Also, a greater degree of detail and certain reclassifications would occur in practice, because the asset 'estimated petroleum royalties' would give rise to a long term receivable, while royalty reports and undisbursed cash are current assets.

Year-End Timing: It must be noted that currently when recording the corresponding liabilities for end of period assets, MMS employs an agreed-upon procedure whereby we estimate the percentages allocable to our three largest recipients; U.S. Treasury, Reclamation Fund and the States. In the proposed ED models, due to the magnitude of the asset value, even the estimated 1% that MMS receives in annual appropriations becomes material. This creates a situation where each recipient will require a liability entry based on some estimation method, and each designated federal recipient will be required to record a corresponding receivable and transfer in their statements, with eliminations between entities to prevent double counting government wide. You will see later in the text that any adjustment made to the asset results in an effect upon the recipient which will require an entry. This becomes especially critical at quarter ends and at fiscal year end, where late adjustments required to accruals that are deemed related to oil and gas revenue (and hence, depletion) will also require late adjustments by all downstream recipients, thus significantly hampering entities ability to meet accelerated financial reporting due dates and potentially giving rise to audit findings.

Availability of EIA Data: The first step in obtaining quantity was to determine **what portion of all proved reserves fall under federal domain**, before the federal royalty share of those proved reserves could be estimated. **This information is presently not published by EIA**, so an estimation methodology had to be developed. **The MMS/OMM/BLM Team reached agreement on the estimation methodology described herein, and ascertained that in the absence of better information, this would be an acceptable method to use for implementation as well.** Please refer to entry #1 above, for more discussion.

Timing of EIA Published Data – Adjustment Factors: As developed by MMS OMM in the alternative view, there is an inherent problem with any method of booking the value of oil and gas reserves. The problem occurs because an estimate of proved reserves is a dynamic quantity as long as there is production from an area and continued development in the area. Proved reserves estimates are a "snapshot" of the oil and gas quantities as of a given date. For example, the FASAB Exposure Draft proposes to base its values on Energy Information Administration (EIA) estimates of proved reserves. For example, if the first such estimated value were to be booked at the start of fiscal year 2009 (October 1, 2008), the EIA reserve estimates available to calculate the value would be effective on December 31, 2006. This is a full 21 months prior to the effective date of the estimate of value.

This raises several concerns. **First, in the months that will transpire between the effective date of the reserves estimates and the effective date of the value estimate, the reserves estimate will have been reduced by any depletion of the reserves through production. Second, over the same time period, the reserves estimate will have been increased through any additions to reserves that naturally occur as accumulations are explored and developed.**

The decreases due to intermediate production and the increases due to new proved reserves additions that occur between the effective date of the reserve estimates and the effective date of the booked asset value represent true and measurable variations in the final proved reserves estimate that must be factored into the final asset value. The MMS proposes incorporating a factor for this variation in the final estimated quantity, such as has been developed by the MMS OMM subject matter experts and described in the OMM alternative view field test response.

This adjustment factor is not included in the current ED view, nor was it performed in the field study of the ED view, and highlights a significant issue requiring resolution before implementing any valuation methodology.

ED par. 38, Published EIA Data: The FASAB Exposure Draft view proposes to base values on, “...the most recent survey conducted by the EIA, issued no more than twelve (12) months before the end of the reporting period...” However, if the first such estimated value were to be booked at the start of fiscal year 2009 (October 1, 2008), the EIA reserve estimates available to calculate the value would be effective on December 31, 2006. This is a full 21 months prior to the effective date of the estimate of value. Accordingly, we recommend the ED be worded to base valuation simply on the most recent survey available from EIA.

Obtaining, Classifying and Stratifying the Royalty Reported Data: Initially, it took quite a while to perform and re-perform numerous queries, and to reach agreement on the commodity ‘buckets’ to be included in the various ‘royalty’ categories. This was necessary to obtain royalty reported production data which could be compared to EIA estimated production data nationwide, to then compute the estimated proved reserves under federal domain. MRM has developed a statistical reporting tool which is structured around certain decisions related to the placement of each element of activity, and a fairly thorough understanding of those elements was necessary before data could be compared on the same footing with EIA data. Certain assumptions had to be made, such as excluding certain volumes for royalty relief and estimating values for the SPR. Also, it took time initially for CRB to perform the calculations by commodity and for onshore vs. offshore, of the federal domain estimated proved reserves, and to perform quality checks and validations of each formula and each step, as well as variance analysis. The BLM Team members had to suspend their portion of the onshore study until this data was available, which added to the length of time it took to complete the study. It should be noted that this is a time-consuming effort that will require refinement and if the ED view is implemented, will be laborious to complete and subject to a high degree of audit review. Adequate numbers of knowledgeable staff will be crucial and careful reviews and quality control will be key to success, because the slightest error could have material repercussions, and could impact all downstream recipients as well.

ED par. 9 – 14; Calculating average prices and average rates. When the annual calculations are performed, the timing of available reported royalty data is such that a 2 month lag may exist from the month of production (the sales month) to the month of required royalty reporting. So for example, if calculating annual averages at September 30, the 12 month average based on “the preceding 12 months” would have to be computed on royalty reporting received for sales months July to June. In this example, if a paid estimate was in place for June production, royalty reporting could be deferred for 2 months from the month of production, and not be received until August – the month immediately preceding the month when calculations would be performed. **This is the method that was used for calculating asset value using the ED view.**

Accordingly, the text in these paragraphs (and elsewhere in the Statement) should provide for this by inserting, “...**that royalty data for corresponding production (sales) months is available...**”

For example, pp. #14. “The effective regional average royalty rate for gas is calculated by dividing the royalty value (royalties) earned on the dry gas reserves produced for each associated region for the preceding twelve (12) sales months that royalty data for corresponding production is available by the total sales value of that production for the preceding twelve (12) sales months that royalty data for corresponding production is available.”

Calculations of Asset Value; Appendix C, Entry #1; We recommend that if using the ED view, the Statement and Appendices clarify that the major commodity categories in common between EIA and MMS be disaggregated, the averages computed separately, and then summed to derive the asset value. Please refer to the discussion in entry #1 above.

Wet Gas vs. Dry Gas – ED View:

Royalty information reported to MMS/MRM is reported as the commodity was sold or removed from the lease. This is important to note, as some assumptions had to be made in conducting the study of the ED view, and will exist at implementation. As regards wet vs. dry gas, MMS can only retrieve it as it was reported. Where reported and paid separately, dry gas had to be analyzed separately from wet gas, and NGL's were also analyzed separately, averages computed and the totals then summed, in order to derive a more accurate estimate.

Earned Revenue Based Upon Royalty Reports; Royalty Adjustments to Prior Periods:

In addition to current royalty amounts, MMS records earned revenue in the current period for the sum of both positive and negative amounts resulting from upward or downward adjustments to prior royalty reporting, related to previous months when the commodity had been either sold or removed from the lease (**sales months**). This is a standard business process in oil and gas industry reporting, resulting from the receipt of subsequent information related to previous reporting periods that was unknown when the compulsory reporting was legally due, such as revised pipeline statements. These adjustments frequently cross monthly, quarterly, and fiscal year boundaries, can be large amounts, and are routine.

If depletion expense is linked across the board with overall revenue earned in the current year, then it must be understood that it would be at least partially based on revenue earned in the current year that is related to adjustments to prior periods falling outside the fiscal year. Therefore, the asset would be depleted in the current year based upon activity that does not actually reflect true depletion in the actual year.

If depletion expense were alternatively based upon revenue earned for oil & gas royalty reports related to current year production only, to most closely reflect the actual asset depletion in the current year, it would be applicable to only the **sales months** falling within the fiscal year. This would exclude prior period adjustments to royalty reporting that would be deemed unrelated to depletion in the current year.

However, complete royalty reporting covering production in the current fiscal year measured at 9/30 can only be ascertained through August, which covers actual reported royalty production through June (for which delayed reporting would not be due until August if a paid estimate were in place). In other words, only 9 months of complete sales month (production) data within a given fiscal year are available at 9/30 if basing ‘revenue earned’ and depletion expense only on current fiscal year sales months; October through June. Clearly, this would not present a

complete picture of current year asset depletion, because it would not even include a full 12 months of royalty reporting.

Earned Revenue; Document Level Royalty Reporting Accruals vs. Line Level Royalty

Detail:

When a royalty document is received, it usually includes numerous individual 'lines' of reporting. Each line contains specific detail about the royalty, such as the individual lease number, sales month and product code. If even one line of the royalty document passes edits and accepts in the royalty accounting system (MRMSS), then revenue is recorded for the full 'document calculated total'. If all lines reject, then a manual accrual is made for the full 'document calculated total'. Priority is placed on clearing rejected lines as quickly as possible, generally in the month following receipt. In subsequent periods, as the previously rejected royalty lines are corrected and accept in the MRMSS, they do not give rise to revenue, as it was already properly accrued when the document was first received.

As you can see, the detail required in the ED for 'earned revenue' by oil or gas and onshore vs. offshore is not readily obtainable for this portion of the population (rejected lines in the last month of the year). For purposes of the field study, CRB undertook an initial effort to ascertain in a 1-month period, the detail related to line level royalty revenue earned by oil or gas and onshore vs. offshore. In instances where the doc calc total giving rise to revenue in the period did not equal the sum of the accepted lines in the system, CRB developed a method to allocate (estimate) earned revenue to detail associated with existing lines. **This identified a significant problem in our ability to report accurately on the detail associated with 'earned revenue' based on current month royalty reporting. In many cases, the revenue was allocated to oil or gas based upon an estimate that may or may not be correct, and which may not prove to be correct in subsequent periods when the rejected lines are corrected and accept in the system. This issue further supports the premise that depletion be based solely upon accepted royalty reporting lines for given sales months, as presented above, and not on accruals and estimates.**

Earned Revenue; Estimates and Manual Accruals: When examining 'earned revenue' and its relationship to asset depletion, CRB performed an extensive analysis for the field study, of estimates and manual accruals related to current period royalty revenue.

MMS records numerous manual accruals to fairly present assets, liabilities and revenue in the financial statements. One such entry is the 'royalty accrual', a large accrual that represents estimated production in the current month for oil, gas and solid minerals, where the royalty reports are not yet received. The royalty accrual is not computed based on sales month (production month), but rather upon when the royalty report was received. It is computed based on a 12-month average of previous royalty reports received. Revenue recognition for royalty is consistent therefore, because **prior period adjustments to previous royalty reporting are treated as current year revenue, upward or downward, and factored into the current period royalty accrual. The royalty accrual is subject to extensive year-end audit review, and a large subsequent adjustment may be required annually, later in the financial reporting process (early November). If included in the revenue matched with depletion expense, this would also then, require that the proved reserves asset be adjusted accordingly, and would impact materially, all allocated downstream recipients as well.**

The royalty accrual is required to be performed fairly quickly, at the high level, to meet accelerated financial reporting objectives. **It includes adjustments to prior reporting periods, and it does not contain the detail required in the ED, to break out oil vs. gas and onshore**

vs. offshore. Of course, a rough estimation method could always be developed, but its accuracy and validity when compared to subsequent actual information could potentially prove to be incorrect.

Another significant manual accrual involves **unmatched cash** for which no royalty report has been received at the end of the reporting period. This occurs monthly, and this large unmatched cash balance can not accurately be linked to oil or gas, onshore or offshore. In some instances, large compliance settlement amounts may be included in the cash balance, not related to current year royalties. Large amounts could be related to interest payments. It would be incorrect to allocate current year depletion to unmatched amounts that may not be related. **Also, this unmatched cash, when applied to subsequent royalty reports, will likely relate to adjustments to prior reporting, and also not bear a relationship to current year asset depletion.**

Previous discussions with FASAB Staff indicated that in order to provide matching of royalty revenue earned in the fiscal year, the royalty accrual would be included in the 'revenue earned' that would be offset by depletion expense, because the accrual estimates production in the current month for which royalty reports will not yet be received. Also, it was discussed that revenue recognition overall should remain consistent, and that revenue earned in the fiscal year, regardless of sales (production) month and subsequent adjustments, would still apply. Accordingly, the text in pp. #23 and throughout the Statement was going to be revised to include, "Royalties received and accrued..."

However, upon analysis **as a result of the field test study**, it is apparent that the degree of detail required to be estimated, allocated and reported is very extensive, labor intensive, **includes adjustments to prior period reporting which may not relate to current period asset depletion at all, and poses significant risks to meeting audit and accelerated financial reporting objectives.** Again, including these and other estimates, by default, **includes adjustments to prior reporting, or other activity not necessarily related to actual current period asset depletion. The degree of detail for disclosure required in the ED would not be readily available from these estimates, and would have to be extensively estimated.** And the inclusion of these estimates would likely not yield a better, and perhaps a worse, measure of actual asset depletion in the year, as opposed to the recommended sales month method described above. For the many complex accruals currently performed by MMS, estimation methods would have to be developed to allocate some portion of the earned revenue to oil and gas, and then of that subset, to onshore vs. offshore.

For purposes of this field test study, revenue overall is presented in aggregate, includes estimates and is based upon royalty reporting lines received and accepted in the fiscal year, regardless of sales months, to tie with current practices. This is done to illustrate the many estimates performed, their relationship to earned revenue, and to explain why the detail required in the ED can not currently be provided. However, it is not the recommended method for deriving depletion expense. Also, disclosures were not attempted.

As we have discussed, estimations pose significant challenges to MMS' ability to produce adequate detail in the required disclosures regarding revenue earned by oil and gas and onshore vs. offshore categories. **It currently could not be readily done with existing resources or information.** Each line of each component of earned revenue would have to be carefully analyzed, an allocation method developed for oil and gas and onshore vs. offshore, and would be an extensive and labor intensive process. A sophisticated system report and

queries could be developed to help provide some of this degree of detail, but it would not resolve issues around allocations of estimates, and **timing would be crucial, as reconciliations and adjusting entries would need to be made quickly, to meet accelerated financial reporting deadlines, and to pass audit requirements.**

Again, the primary concerns related to recording depletion expense based on revenue which includes estimates revolve around mismatching unrelated portions of estimates with actual asset depletion, potential material audit findings and a potential inability to meet accelerated financial reporting objectives.

As an aside, if using the recommended sales month method described above for ascertaining the amount of depletion to record in a fiscal year, then the actual royalty value for oil and gas reported to MMS was approximately \$9.2 billion for the most recent sales months available when performing the field test, June 2006 through May 2007, obtained in mid-August 2007.

To restate, some of the key concerns around recording depletion expense based upon the sum of current year royalty reports and estimates include:

- ✚ Revenue and depletion expense would be mismatched due to prior period adjustments not related to current period depletion captured as revenue in the current year.
- ✚ The revenue estimate including accruals would also include estimates of production anticipated through year-end, and estimates of unmatched cash with estimates sub-allocated to oil & gas, and then sub-allocated to onshore vs. offshore. The estimated allocations will likely be later found to be incorrect. Also, the estimates include adjustments to prior periods, not attributable to depletion in the current period.
- ✚ Each estimate is already complex to derive, and currently does not include a method for allocating to oil or gas, or onshore vs. offshore.
- ✚ Revising each estimate accordingly will decrease the likelihood of meeting accelerated financial reporting objectives, and will increase the likelihood of audit failures, and their severity based on materiality.
- ✚ Estimates and subsequent changes to estimates will impact the asset value through depletion expense, and so, all designated downstream recipients.
- ✚ Estimates measured against subsequent actuals at fiscal year end will likely result in material adjustments near the close of the annual financial audit process in early November, and also require adjustment by designated downstream recipients.

Settlement Amounts: Each year, MMS receives payments as settlement on compliance or enforcement cases that are reported generically as custodial 'Rents and Royalties'. The settlement payments are generally matched to a royalty report that does not break out what portion may possibly be estimated to be related to commodity royalties, or interest, or civil penalties. The royalty report simply contains an amount with no product code, so can not be broken out. As a result, these amounts were excluded from the values used to compute the capital asset and from amounts used to compute depletion expense. This will more often than not, be correct, as the compliance 3-year cycle produces settlements generally related to prior periods, appropriately falling outside of the relevant periods for capitalizing or depleting. However, internal process would need to be changed to capture more detail in the event that royalty or other amounts were compliance amounts brought current. This highlights a potential pitfall in the ED view for valuation. Currently, performing a 12 sales month 'look back' of royalty reports would by definition exclude potentially large royalty amounts not captured at the degree of detail necessary to identify them.

Invoiced Amounts: Periodically, MMS receives royalty related payments against invoices that are reported generically as custodial 'Rents and Royalties'. The invoice does not provide for a product code or other detail related to the nature of the obligation, but simply contains an amount due with no product code, so can not be broken out further. As a result, these amounts were excluded from the values used to compute the capital asset and from amounts used to compute depletion expense. Internal system process would need to be changed to capture more detail in the event that royalty or other amounts were invoiced. This highlights a potential pitfall in the ED view for valuation. Currently, performing a 12 sales month 'look back' of royalty reports would by definition exclude potentially large royalty amounts not captured at the degree of detail necessary to identify them.

ED, par. 23; Royalties and Depletion Expense on Statement of Net Cost (SNC):

Please refer to the extensive discussion in entry #6 above.

Paragraph 23 states,

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

Appendix C, entry 6, page 54 states,

"Earned royalty revenue should be recognized as exchange revenue by the component entity that is responsible for collecting the royalties. At the same time, an amount equal to the royalty collections should be recognized as depletion expense; and, the value of estimated petroleum reserves should be reduced by the depletion expense amount. Sales value and royalty payment information are due on or before the last of the month following the month the oil or gas product from federal oil and gas resources was sold or removed from the lease. For example, oil or gas sold in June must be reported by July 31, the end of the following month. For illustrative purposes, the total amount of royalty revenue earned for the fiscal year for offshore and onshore rental leases was used in this calculation."

In order to exclude adjustments to prior period reporting not attributable to depletion in the current year, and to exclude potentially unrelated estimates from the depletion calculations, **the recommended method is to record depletion based upon royalty reporting lines received and accepted for the preceding 12 sales months available at fiscal year end; July through June (received through August, fully available in September). Revenue earned would not be a perfect match in the fiscal year, but in this case it should not, because depletion in the current year should not be linked to prior adjustments not related to the current year.** To do otherwise would include prior period adjustments not related to depletion in the year, and would involve complex and extensive inclusion of current year estimates that are potentially unrelated to depletion and also include prior period adjustments. **This method would likely yield a more accurate picture of current asset depletion over a year span. This method would also provide the ability, with sophisticated queries and system reports, to derive the detailed information the ED requires from actual royalty reports, such as commodity type, Region, onshore vs. offshore and other necessary details.**

New Accounting Treatment, SGL Accounts and Accounting Models Required: In discussions with Treasury SGL experts, new Standard General Ledger (SGL) accounts,

reciprocal pairs and posting models will need to be developed, approved, and incorporated into Treasury financial statement crosswalks. For example, some transfer pairs will involve transfers from a clearing to a special fund, some with and some without budget authority. Also, currently there is not a precedent for recording equity in a general fund or a clearing account. Treasury has indicated however, that it is their policy that until a FASAB Statement is finalized they do not develop or implement new sgl accounts, reciprocal pairs, or models. Accordingly, the final details of implementation remain to be developed. Until formal Treasury approved accounts and models are in place, MMS can not engage with the system contractor to build and modify the required accounts and models needed for implementation. Adequate time is requested for Statement implementation, to facilitate this significant and costly effort.

New Fund or Reporting Exception Required: Currently, MMS/MRM appropriately records royalty and related activity flowing through clearing account F3875. Amounts are received from the public and distributed to other federal entities. To capture and report on the capital asset and associated depletion expense, a new fund would be required, or an exception granted to report this activity, including equity, in the clearing account. While Treasury is in the midst of prohibiting or limiting use of the F3875 clearing account, a waiver request is in process for MRM royalty activity and Treasury has indicated that it will likely be granted. Historically, Treasury and OMB mandated that MRM use this clearing account for their royalty and related activity, and it is hard-coded throughout the MRMS.

ED pp. 21, 23, 46, 47; Exchange revenue recognition based on SFFAS 7 pp. #34 and reported on SNC; Payments to States and Counties. Royalty payments are made to States and Counties through permanent indefinite appropriations, and reflect the budgetary authority both derived and expended based on actual receipts and disbursements. Payments to States and Counties are made from MMS's royalty clearing account F3875 into permanent indefinite appropriated funds, from which they are ultimately expended. Since MMS is the final entity to receive the cash before it leaves Government custody, it is recorded as a transfer to a special fund, where it is then treated as an obligation and outlay. Accordingly, the custodial transfer account shows the current trading partner, G.1417 (MMS), in accordance with specific FASAB guidance. These special funds are presently reported as 'earmarked'. There are unique and detailed implementation issues associated with ensuring the proper accounting for this activity, based upon the new proposed treatment in the ED. In discussions with Treasury SGL experts, at the least, a new transfer account reciprocal pair would need to be developed. They have indicated however, that it is their policy that until a FASAB Statement becomes finalized they do not develop or implement new sgl accounts, pairs, or models. Accordingly, the final details of implementation remain to be developed, and adequate time is requested for Statement implementation, to facilitate this effort.

ED pp. 21; Exchange revenue recognition based on SFFAS 7 pp. #34. The Statement proscribes that, "Revenue from exchange transactions should be recognized when goods or services are provided to the public or another Government entity at a price."

MMS/MRM records as revenue in the current period, both positive and negative amounts resulting from adjustments to prior royalty reporting, for sales (production) months other than just the current months. This is a routine business process in oil and gas industry reporting, resulting from numerous events where subsequent information is received related to previous reporting periods that was unknown when compulsory reporting was legally due, such as pipeline reallocations, revised gas plant statements, unit reallocations, and pricing revisions. The volume of these adjustments to prior period royalty reporting is significant, recurring, and

may span multiple years. This practice is foundational to royalty reporting. We request that the Board consider clarifying related provisions in the ED accordingly.

Also, please refer to the additional discussion in entry #6 above.

ED pp. 46-47; Rescission of amendments to SFFAS 7 related to bonus bid, rent, and royalty revenues. The Statement does not address all commodities accounted for by MMS/MRM, such as solid minerals (and related interest). This creates a significant disparity in accounting treatment, and would result in the capitalization and depletion of only oil and gas, while other commodities would not be capitalized, yet would not be covered under any FASAB provisions. We are presuming that all commodities not covered under the ED would continue to be treated as custodial, according to established provisions in SFFAS 7, pp. 45, 275, 276, and 277. We request that the Statement clearly provide for these commodities, and allow current practices related to them to continue as custodial under existing guidance in SFFAS 7.

As mentioned above, the Statement does not address interest derived from royalty related activity, currently also treated as custodial. The interest component bears no relationship to depletion of the asset, but if related to oil or gas, guidance is needed regarding accounting treatment, to determine if it should still be treated as custodial or on the SNC.

It is strongly recommended that all other commodities and related business activity be addressed in this Oil & Gas Standard before implementation, due to the significant issues and costs related to differing treatment.

Long term vs. short term liabilities: The Exposure Draft and accompanying Appendix C do not break out or distinguish between long or short term liabilities, nor does the pro forma balance sheet present them separately, in relation to the nature of the offsetting assets. While it is understood that the Appendix C entries and statements are illustrative and not meant to present all associated detail, the break out and disclosure of long term vs. short term liabilities is a financial reporting requirement, and poses some issues around implementation. In order to comply with reporting requirements of OMB Circular A-136 and FASAB SFFAS 1, current liabilities must be reported separately from non-current (long term) liabilities.

Clearly, the royalty reports and cash received that remain unmatched at the end of a reporting period are current, as they are generally remitted on the legal due date, and payable in the subsequent month. We request that this be clarified in the Statement and Appendices. However for the new asset 'Estimated Petroleum Royalties', no mention is made that any portion of the associated liability might be short term or 'current'.

FASAB SFFAS 1, pp 83 states 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." Further, pp. 86 requires, "The reporting entity should disclose the amount of current liabilities not covered by budgetary resources." And the Glossary defines current liabilities as, "Amounts owed by a federal entity for which the financial statements are prepared, and which need to be paid within the fiscal year following the reporting date."

For the liability related to 'Estimated Petroleum Royalties', some amount will be liquidated and transferred to recipients in the subsequent year, and should therefore be reported as current.

The entries demonstrated in Appendix C for the recipient 'Other Federal Component Entity' would likewise be affected. We request this be discussed in the Standard and associated Appendices.

The methodology for computing what this current portion might be is subject to debate, but must at least be fairly readily computed, in order to meet short timelines for annual financial statement preparation. It could be based upon the same value reported as depletion expense in the current year. This would be perhaps the best method, as the value would already be computed, reconciled, and audited, and would be most representative of current market conditions that could be expected to occur in the immediately subsequent year.

However, its complexity is greatly increased if it must only relate to oil and gas, as the current ED only includes oil & gas.

If, FASAB determines that the liability related to 'Estimated Petroleum Royalties' should be all classified as long-term (non-current), we request that the Statement clarify this point for implementation.

ED pp. 34; Fiduciary Reporting Requirements:

Currently, EIA does not publish numbers related to proved reserves on Indian lands. Further, MMS only receives a small portion of royalties related to Indian leases, which are distributed to OST for subsequent funds management and distribution to Tribes. Accordingly, there is presently not a means for MMS to know how to estimate an asset value, nor how to present estimated depletion. While estimates could always be developed, the validity of the data could later be proved to be incorrect, and would be a very broad estimate at best.

Potential Impacts to BLM Accounting and Custodial Statement: BLM receives some royalty amounts that are transmitted 2 or 3 times per month to MMS/MRM, where they are then matched to the lease and distributed according to lease terms. The BLM receipts and distributions to MMS are captured as custodial activity and reported on the Statement of Custodial Activity (SCA). For purposes of the Statement, we do not currently think this would pose a problem, as MMS would still be the 'collecting entity' who bears the responsibility for reporting on the satisfaction of the lease obligation and would record the depletion expense. BLM also receives 'Rights of Way' payments on leases for which the Bureau of Reclamation, the General Fund of the Treasury and States are designated recipients. These payments do not relate to commodity depletion, nor do they flow through MMS at any time. They are also recorded on the SCA. At this time, it does not appear that the Statement would impact this activity, or result in the elimination of the BLM SCA. However, we ask that the Board consider this when finalizing the Statement.

ED pp. 31 d, Component Entity Disclosures: As discussed previously in this document, earned revenue includes numerous components including estimates, which can not be readily broken out into categories such as onshore vs. offshore, etc. We request that the Statement clarify the disclosure requirement, such that the disclosure relate specifically to the royalty data linked with depletion expense, and indicate that it is not all-inclusive of total revenue recorded in the financial statements for the period.

ED pp. 32 a & c, Component Entity Required Supplementary Information (RSI): The information required to be provided in the ED is not available, and so **could not be provided by the MMS. This is information that can only be gathered and provided by the EIA.** As discussed in the valuation process above, MMS had to obtain EIA nationwide data and develop

a rough estimation methodology to attempt to arrive at an estimate of the estimated proved reserves under federal domain. The additional information required in the ED for RSI disclosure, such as federal domain technically recoverable resources, onshore and offshore, and historical 10-year information on federal domain estimated proved reserves could only be provided by EIA. If the Board intends that estimated calculations be produced, we request that be clarified. However, such things as net revisions, extensions, new field discoveries, etc. could not be reasonably ascertained.

Tab F-3
Natural Resources History of Project
and Key Decisions

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. Leshar 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. Leshar 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 Leshar 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. Leshar said the task force expected to complete work on the remaining sections of the fact-finding paper in about 6 weeks.

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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/pdf/files/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.

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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

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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 Wascak retired.

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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.