Federal Accounting Standards Advisory Board

September 23, 2004

Memorandum

To: Members of the Board

From: Rick Wascak, Assistant Director

Through: Wendy M. Comes, Executive Director

Subj: **Oil and Gas Valuation Paper**[1]

Following is a paper that presents the proposed valuation approach for valuing the Federal asset "Estimated Petroleum Royalties." The paper was developed based on discussions at the August 2005 Board meeting. The paper will be discussed at the October 2005 Board meeting.

Estimated Petroleum Royalties is a term used to connote the estimated current fiscal year value of the Federal government's royalty share for proved oil and gas reserves on lands under the control of the Federal government. The contents of the paper will be incorporated into the Basis for Conclusions section of the exposure draft (ED) for oil and gas. While the enclosed paper addresses only the proposed valuation approach for Estimated Petroleum Royalties, the accounting standards for oil and gas will also address disclosure requirements for oil and gas resources, i.e., probable reserves and possible reserves.

The objectives for the meeting are:

1. Discuss the proposed valuation approach for valuing the Federal asset Estimated Petroleum Royalties.
2. Obtain approval from the Board on the proposed valuation approach.
3. Obtain feedback from the Board regarding areas of the paper to be clarified or expanded.

If you have questions or comments before the meeting, please contact me at 202 512-7363 or wascakr@fasab.gov.

[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.

Valuation of the Federal Asset "Estimated Petroleum Royalties"

The Board tentatively believes that the most relevant and sufficiently reliable measurement of "estimated petroleum royalties" would be obtained by multiplying the estimated aggregated quantity of proved reserves by the national average wellhead price (for natural gas) or first purchase price (for oil) and a national average royalty rate. This calculation would provide the value of the "estimated petroleum royalties" for proved oil and gas reserves on lands under the control of the Federal government as of the last month of the reporting period. The formula provided is:

(Estimated Quantity of Proved Reserves X National Average Wellhead Price or First Purchase Price) X National Average Royalty Rate = Estimated Petroleum Royalties)

The Board believes using the components of this formula would provide a conservative representative value of the estimated proved petroleum reserves, without having to use proved reserve, price, and royalty rate information on a field-by-field[2] basis. The Board believes it would not be practicable to make calculations on a field by field basis to calculate a value of the estimated proved petroleum reserves. There are more than 60,000 leases maintained by the DOI with approximately 115,000 producing wells. In addition, the EIA maintains only the proved reserve information for each field, which it aggregates; while, the DOI maintains only the price and royalty rate information for each field.

A description of each component in the formula is provided in the following paragraphs.

Estimated Quantity of Proved Reserves. The Board proposes that the estimates of proved oil and gas reserves on lands owned or under the control of the Federal government be used to calculate and value the "estimated petroleum royalties" to be capitalized. The source for the estimates of proved oil and gas reserves would be the Energy Information Agency (EIA), based on the required field-by-field filings by oil and gas operators.

The EIA defines proved reserves as those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves, however, are not quantities that can be counted; nor, are they direct measurements. They are estimates. Proved oil reserves are estimated in thousands of barrels at 60 degrees Fahrenheit. Proved gas reserves are estimated in thousands of Cubic Feet (MCF) at 14.73 PSIA and 60 degrees Fahrenheit. For purposes of this standard, proved "natural gas liquids" reserves are included in the proved oil reserves.

EIA's proved reserves estimates are based on data filed by: 1) large, intermediate, and a select group of small operators of oil and gas wells; and, 2) operators of all natural gas processing plants. The EIA requires the top 600 operators to submit a direct report of the proved reserves they carry for each field as of December 31. The reports are required to be submitted by April 15 of the year following the December 31 cut-off date. The EIA checks and edits all of the reports at the field level and that number would exceed 20,000 operator field reports. On all the

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

checks and edit steps, the EIA relies on its own engineering staff. In addition, the EIA staff independently checks about 20 fields a year. This can be described as an audit procedure performed by the EIA staff. The fields are selected either because they are new or there is something that might attract attention to the EIA about the field. The EIA points out significant errors or misinterpretations to the operators.

The EIA has been reviewing the domestic numbers of proved reserves estimates independently for more than 25 years. The EIA observes that if one looks at an individual field you almost always find it to be within professional competence; and, if you look at an aggregate of a number of fields those numbers are even more reliable. The EIA issues a report containing aggregated volume information for crude oil, natural gas, and natural gas liquids. The report is issued in the month of September containing volume information as of December 31 of the preceding calendar year. The information contained in the report has a 99.999% probability that there is at least the physical volume that is estimated.

Estimated proved reserves are calculated in the following manner[3]:

Published Proved Reserves at End of Previous Report Year
+ Adjustments
+ Revision Increase
-- Revision Decreases
-- Sales
+ Acquisitions
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
-- Report Year Production
= Published Proved Reserves at End of Report Year

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

The proved reserve information provided by the operators to the EIA is generally the same information the operators are required to send to the U.S. Securities and Exchange Commission (SEC) in their annual report for oil and gas producing activities. The SEC receives approximately 14,000 financial statement submissions on a yearly basis. Each submission is reviewed on a rotational basis every three years based on internal selection policies and criteria.

<u>National Average Wellhead Price and First Purchase Price</u>.

There are two relevant prices – one for gas and another for oil.

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

The first relevant price is “wellhead price” and is used in the natural gas environment. The wellhead price is the value of the purchased gas at the mouth of the well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. The national average wellhead price for gas would be calculated by dividing the total sales value of gas for the last month of the reporting period by the total sales volume of gas for the last month of the reporting period. For example, if the total financial sales value for gas was $18,824,102,982 and the total sales volume was 6,789,523,253 MCF of gas[4], the national average wellhead price would be $2.77 per thousand cubic feet. This information is available to the Minerals Management Service (MMS). Sales value and the sales volume information is provided to the MMS by gas producers on a monthly basis.

The second relevant price is “first purchase price” and is used in the crude oil environment. A “first purchase” constitutes a transfer of ownership of crude oil during or immediately after the physical removal of the crude oil from a production property for the first time. The proposed national average ”first purchase price” would be calculated by dividing the total sales value of oil for the last month of the reporting period by the total sales volume of oil for the last month of the reporting period. All types of crude oil streams and gravity bands are aggregated for this calculation. For example, if the total financial sales value for oil was $12,762,548,440 and the total sales volume was 666,108,296 barrels of oil, the national average first purchase price would be $19.16 per barrel. This information is available to the MMS. Sales value and the sales volume information is provided to the MMS by oil producers on a monthly basis.

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

National Average Royalty Rate. Royalty rate is a proportionate interest in the production value of mineral deposits due the lessor from the lessee in accordance with a lease agreement (see Attachment 1). For many years, the federal government made oil and gas resources available to developers under the terms of the Mining Law of 1872, which offered properties on a noncompetitive basis for flat, per-acre fees. The current federal royalty program originated in the Minerals Leasing Act of 1920. Later, the Acquired Lands Act of 1947 extended the leasing authority of the 1920 act over lands in the public domain to include areas that the federal government acquired from states and individuals. The Outer Continental Shelf Lands Act of 1953 revised the oil and gas leasing program to make offshore leases available through competitive auctions. The most recent major changes to the program came with the Federal Onshore Oil and Gas Leasing Reform Act of 1987. The Congress passed the Federal Onshore Oil and Gas Leasing Reform Act of 1987 to require that all public lands that are available for oil and gas leasing be offered first by competitive leasing. Noncompetitive oil and gas leases may be issued only after the lands have been offered competitively at an oral auction and a bid was not received. Those basic laws establish procedures for leasing public lands to developers, collecting compensation from the developers in the form of initial payments and royalties on subsequent production, and disbursing the receipts to various government accounts and to the states.

[4] MCFmeans thousand cubic feet.

Because the Board believes using proved reserve, pricing and royalty information from each field would not be practicable, a meaningful and relevant royalty rate was needed in calculating the representative value of the estimated petroleum reserves. The Board, therefore, proposes that a national average royalty rate be used. The national average royalty rate would be calculated by dividing the total financial sales value for all oil and gas reserves that were produced for the last month of the reporting period by the financial royalty value (royalties) due on all of the oil and gas reserves that were produced for the last month of the reporting period. For example, if the total financial sales value for oil and gas was $31,586,651,422 and the total royalties due on the produced reserves was $4,406,985,439, the national average royalty rate would be 13.952%. This information is available to the MMS. Sales value and the royalty information is provided to the MMS by oil and gas producers on a monthly basis.

Conclusion

The Board believes using the described components in the formula for calculating the estimated proved petroleum reserves would provide a representative value of the estimated proved oil and gas reserves on lands under the control of the Federal government for the last month of the reporting period. The information provided for each component is verifiable and reliable. In addition, it is consistent and relevant. That is, it is aggregated at the national level, it is based on recent oil and gas production activities, and it incorporates recent economic trends.

Attachment 1

POSSIBLE ROYALTY RATES

Royalty Rate – Federal Onshore Leases

Competitive

- Leases issued under the Mineral Leasing Act of 1920 (prior to 12/23/87): oil royalty assessed on production amount ranges from 12.5% to 25%; gas royalty assessed on production amount ranges from 12.5% to 16.67%.
- Leases issued 12/23/87 forward: flat rate of 12.5% in amount or value of production.

Non-Competitive

- Based on 12.5% in amount or value of production.

National Petroleum Reserve-Alaska (NPRA)

- Set by regulation at 16.67%.

Royalty Rate – Federal Offshore Leases

Not Under Deepwater Royalty Relief Act (DWRRA)

Is set for each sale area in its Final Notice of Sale. It may be:

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

Under Deepwater Royalty Relief Act

Certain Gulf of Mexico (GOM) deep water leases issued under DWRRA between 11/28/95 and 11/28/00 receive royalty suspensions based on the following criteria:

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

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

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