Federal Accounting Standards Advisory Board

August 5, 2005

Memorandum

To: Members of the Board

From: Wendy M. Comes, Executive Director

Subj: Natural Resources – Tab C1 – Advance Briefing Materials[1]

Following is a paper presenting the Department of Interior's responses to our inquiry regarding oil and gas proved reserves. Interior responses to specific questions are presented following each question and appear in the larger font. Representatives of the department will be available at the meeting to discuss these responses and other questions you may have.

[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.

Background

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

The Board members suggested that the FASAB staff initially address each type of natural resource in phases, (i.e., separately and individually) and to begin with developing accounting standards for natural resources. The Board was interested in determining whether values, or some surrogate, for natural resources could be capitalized and reported on the balance sheet. The Board members believed that capitalizing natural resources would increase accountability over them and improve the comprehensiveness and consistency of federal financial statements. The Board decided to proceed with developing standards for oil and gas resources first due to the literature available in other domains, the extensive historical information on Federal lease programs and royalty collections, and the large amount of monies collected for oil and gas resources.

Initially, The Board explored options for forecasting the anticipated revenue stream flowing to the Federal government from royalty collections based on historical information. When the Board learned that estimated proved oil and gas reserve quantities from lands under Federal control were accessible, it tentatively decided that capitalizing the current value of the estimated future revenue flow from the Federal government's royalty share of proved oil and gas reserves was feasible. The Board also suggested that the capitalized future revenue flow be referred to as "estimated Petroleum Royalties."

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 quantity of proved oil and gas reserves on a field-by-field basis by the national average wellhead price/first purchase price and the respective royalty rate on a field-by-field basis. This calculation would provide the value of the "estimated petroleum royalties" of proved oil and gas reserves on a field-by-field basis as of the end of the reporting period on lands under the control of the Federal government. The formula is provided is:

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

The value of the "estimated petroleum royalties" for each field would be accumulated to provide the value of the Federal asset "estimated petroleum royalties."

A description of each element in the formula is provided in the following paragraphs based on the FASAB staff's understanding of the elements.

Estimated Quantity of Proved Reserves. The Board is considering a proposal that the estimates of proved oil and gas reserves on lands owned or under the control of the Federal government, on a field-by-field[2] basis, be used to value the "estimated petroleum royalties" for proved oil and gas reserves 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 names a field by geographic location. The field may have many reservoirs at various depths. Each reservoir is an isolated pressure system. After the oil and gas is extracted from one reservoir, the company moves on to the next reservoir. So, while the EIA requires operators to submit a report about proved reserves on a field-by-field basis, the operators almost always do their estimates at the reservoir level and, for the EIA's convenience, summarize them to a field level.

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 millions of Cubic Feet (MMCF) 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 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 believes all of the proved reserves reported by the EIA will be recovered with a probability rate of 99.99%.

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

Published Proved Reserves at End of Previous Report Year
+ Adjustments

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[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.
[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.

+ 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 on a yearly basis. Each submission is reviewed on a rotational basis every three years based on internal selection policies and criteria.

National Average Wellhead Price and First Purchase Price. There are two relevant prices – one for gas and another for oil.

The first relevant price is "wellhead price"[4] and is used in the natural gas environment. Preliminary values for a national average wellhead price, which is referred to as the monthly U.S. natural gas wellhead price in EIA instructions to calculate it, are:

a. estimated from the New York Mercantile Exchange (NYMEX) futures final settlement price for near-month delivery at the Henry Hub, and

b. reported cash market prices at 5 major trading hubs:

    1. Henry Hub, LA;
    2. Carthage, TX;
    3. Katy, TX;
    4. Waha, TX; and
    5. Blanco, NM.

The NYMEX price is publicly available and is reported in numerous trade publications, including the National Gas Intelligence's (NGI) Daily Gas Price Index (published by Intelligence Press, Inc.). The cash market prices are published in another trade publication, Natural Gas Week (Energy Intelligence Group, Inc.), and they reflect the spot delivered-to-pipeline, volume-weighted average prices for natural gas bought and sold at the specified trading hubs. Prices

[4] The source of information used to describe the calculation of the national average wellhead price for natural gas is the *Natural Gas Monthly*, Appendix A-Explanatory Notes.

include processing, gathering, and transportation fees to the hubs. The estimated wellhead prices are derived with a statistical procedure based on analysis of monthly time series data for the period 1995 through 2000. The preliminary estimates are replaced when final monthly survey data become available.

Final monthly survey data are provided through the Form EIA-895, which requests State agencies to report monthly values of marketed production. Form EIA-895 requests State agencies to report the quantity and value of marketed production. When complete data are unavailable, the form instructs the State agency to report the available aggregate value and the quantity of marketed production associated with this value. Information for several States that are unable to provide data is estimated based on price information submitted by neighboring producing States. Preliminary monthly gas price data are replaced by these final monthly data.

In the draft proposed accounting standards, the national average natural gas wellhead price as of the last day of the month for the reporting period would be used to value proved gas reserves. [which month? An average of all months? One would have to average, as the price of gas changes markedly from month to month, depending on a variety of factors. Then one is averaging – and why go to the added expense and human resources to collect each wellhead price, and average it, when the national average is publicly available, publicly traded on, and easily obtained?]

The <u>second relevant price</u> is 'first purchase price'[5] and is used in the crude oil environment. Each month, the Form EIA-182 collects data from first purchase buyers of domestic crude oil. 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. Transactions between affiliated companies are reported as if they were "arms-length" transactions. (This definition is consistent with the Windfall Profits Tax (WPT) concepts of "first sale" and "removal price.") The primary objective is to calculate an average first purchase price at various levels of aggregation.

A company's monthly average first purchase prices are volume weighted across given geographical areas for selected crude streams and gravity bands. Prices are computed from the following reported data elements:

<u>Area of production</u>. The producing State or non-State production "area" (i.e., Alaska North Slope, Alaska South, Federal Offshore California and Federal Offshore Gulf—about one-fifth off the coastline of Texas and the remainder off Louisiana).

<u>Average cost</u>. Reported at the lease boundary (usually at a lease automatic custody transfer unit) and based on the actual purchase expenditures, including any taxes, discounts or premiums paid.

<u>Total volume purchased</u>. The amount of crude bought and paid for as it is measured at the lease boundary, adjusted for basic sediment and water (BS&W) and temperature.

The proposed annual national average 'first purchase price' would be calculated from data collected on Form EIA-182 by dividing the sum of the total average costs paid from all areas of

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[5] The source of information used to describe the calculation of the national average first purchase price for crude oil is the *Petroleum Marketing Annual 2002*, August 2003, Explanatory Notes.

production by the sum of the total volumes purchased from all areas of production as of the last day of the month for the reporting period. This amount would be used to value proved gas reserves.

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. In order to estimate the current market value of the federal interest or share in proved reserves, the royalty rate for each field is required.

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.

While the royalty rate is based on the lease agreement, the Secretary of the Department of the Interior may, upon application from a lease holder, reduce the royalty rate for good cause. Examples where rates have been reduced have been operating conditions that caused costs to be very very high and where a well is approaching the end of its production life. Sometimes the reductions are for the remaining lease term, but more often they are for some limited period of time.

Issues

Presented below are issues raised by Board members during discussions at the March 2005 meeting. The issues are divided into three sets. The first set of issues, issues 1) through 3), are posed to both the **Department of Energy, Energy Information Administration (EIA), Office of Oil and Gas, Reserves and Production Division and the Department of the Interior.** The second set of issues, issues 4) and 5), are posed only to the **Department of Energy, Energy Information Administration (EIA), Office of Oil and Gas, Reserves and Production Division.** The third set of issues, issues 6) and 7) are posed only to the **Department of the Interior.**

Following each issue is a synopsis of comments made by Board members in regard to the issue.

Department of Energy, Energy Information Administration (EIA), Office of Oil and Gas, Reserves and Production Division, and

Department of the Interior

1) Explore the feasibility and advantages of using the wellhead price for each field instead of a national average wellhead price to value "estimated petroleum royalties."

One member suggested that a more specific valuation could be attained if wellhead prices for each field were used in the valuation process. In addition, the member indicated that the MMS has this data and possibly the EIS does, too (staff added). One other member indicated support for the use of specific wellhead prices in lieu of an average and another noted a general preference for more specificity.

Staff believes that the following information would be useful to the members in deciding whether an average or specific wellhead price is to be proposed:

a) A discussion of the universe of prices included in a national average price versus specific wellhead prices; for example, is it feasible to present statistics regarding the percentage of national proved reserves attributable to federal leased proved reserves or a similar percentage based on numbers of wells.

The universe is so large it is not reasonable and is cost prohibitive to provide this analysis. At this time, there is no integrated system available to produce and provide timely information. To provide an extensive database for MMS and BLM that would link to the royalty system at last estimate would cost in the millions.

b) Statistics on price variation among wellheads;

Wellhead prices are unique to each situation and their attendant location and product quality considerations. In the past, MMS has estimated wellhead costs using a single landed price and a formula to derive the wellhead prices.

MMS regulations require use of NYMEX and over ¾ of our agreements are governed by this process. Well head price is extremely variable, as mentioned above, and therefore an average provides a much more reliable (and longer term) indicator. Well head price is variable depending upon geographic locality, type of production, type of resource, market price, and many other factors. The national average gives a very good indicator of what's being produced across the spectrum.

c) An assessment of the availability of and cost associated with obtaining wellhead specific prices;

At this time, there is no integrated system available to produce and provide timely information. To provide an extensive database for MMS and BLM that would link to the royalty system at last estimate would cost in the millions. Though the data is accumulated and exist, staff and resources are not available to accumulate the data into a customized format for outside purposes. We recommend estimating wellhead prices as described.

d) Statistics on any variation between the preliminary national average wellhead price estimates for oil (based on spot prices) and the final monthly survey data (actual data) for the national average wellhead price estimates;

There are so many different indices used and it is not possible to aggregate. Information is available based on field data which would require a significant amount of aggregation that is not currently performed. The issue is that more accurate price information would cost more to derive and that average prices over a period would provide more stability and useful information for comparative purposes.

e) An overall opinion on the tradeoff between a more accurate valuation and the associated cost.

Since the valuation is an estimate there is a more important need to make it meaningful and consistent as opposed to accurate. Estimates have inherent inaccuracies and it will be important to make these understood and not to focus on making a very accurate estimate that is subject to multiple assumptions that are based on estimates. In addition, the use of historical information versus forecasts make the term accurate less meaningful – the term representative is a better classisfication.

Forecasting the future wellhead price trend of each lease would be no more accurate than forecasting national average prices. Further, though these data exist, providing such data for every well, lease, or even every field would be very costly with limited benefits to the quality of the valuation.

2) Investigate whether there is information available on what the average life or timeframe would be for oil and gas well production.

Members expressed interest in whether an average life per well[6] might be obtained and whether the average life could be used as the basis for valuing proved reserves at the discounted present value of future cash flows arising from the proved reserves. This valuation approach may be perceived by some members as theoretically preferable to the draft valuation technique provided in the staff paper. Staff believes that the following information would be useful to the members in deciding whether it is feasible and appropriate to use a discounted present value valuation method or to use the draft valuation method presented in this paper.

a) What factors affect the number of years between inception of a lease and exhaustion of the productive capacity of a well?

There are so many different indices used and it is not possible to aggregate. A multitude of factors affect this timing. However, if the interest is in proved reserves, then a good number of these factors can be eliminated. This is because proved reserves definitions, by the SPE/WPC, require that proved reserves be in such a state of development that their production starting point has either passed or is eminent. This would tend to minimize factors between the acquisition of a property and the commencement of production. That being said, factors affecting the duration of production from individual accumulations are many and varied depending on the number of development wells, whether the production is from oil or gas reservoirs, the production drive mechanism, the reservoir geography, reservoir pressure, and countless others. No two accumulations produce exactly alike which calls for the use of an annual reserve amount stated as of a point in time and not a rolling or perpetual inventory calculation. The fact that these are estimates that fluctuate based on changes in geology, technology and other outside influences minimizes the usefulness of this type of data.

b) Is it possible to say how sensitive the production period is to variations in each factor?

It’s not possible to list all the factors, much less the sensitivities for each. In addition, each well is unique, and this type of analysis just isn’t possible. There is not sufficient data or analysis of available data to provide additional information.

c) Are there data available on the pattern of cash flows historically experienced on leases?

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[6] Staff defines average life per well as the period from lease signing to exhaustion of the productive capacity of the well for all federal leases. The average life per well would be determined based on historical data deemed relevant by management. For example, management may determine that data on experience during the prior fifty years is the most relevant source. Comments are welcome on the appropriateness of this definition.

Yes for current leases there is sales volume, sales value, and royalty paid data exist for every lessee of every lease. For older leases this is not always the case – record keeping standards were not as comprehensive for leases before 1970.

For example, is there an average period with zero cash flow from royalty payments?

This is the case when the lease is a net profit share lease (as its royalty terms) or if the lease has deepwater or shallow water deep gas royalty relief. In fact, the vast majority of active leases are covered by one of these types of royalty relief, further complicating the proposed method.

If so, should the average life per well be refined to include on the average time between lease inception and royalty payments and between exhaustion of the productive capacity of the well?

Depends upon what the purpose is, but average life of the well is not between lease inception and royalty payments, but between production inception and exhaustion of productive capacity, which is almost impossible to estimate, as stated above.

d) Are there data available to calculate an average life per well? If so, please describe the available data and offer an opinion regarding the reliability of the data. If not, please explain what steps would be needed to obtain data.

Reliable data for production from every well exists. This historical data does not provide the information necessary to determine the life of the well. The life of the well depends upon a number of factors that are constantly changing these include: available production techniques, technological advances made during production (which often extends life of a well significantly, as well as amount of resource produced, reserve growth, etc.)

e) Please offer an opinion on the advantages and disadvantages of using an historical average life per well to for use in calculating a discounted present value of future cash flows arising from the proved reserves.

Due to the constant evolution of technology the use of historical factors to net present value cash flows is due to be unreliable. The number of wells that have constant production amounts is smaill and would not be representative of the universe at large.. In addition, production typically declines over the productive life of wells, limiting the value of using the average productive life as a measure to use in estimating the NPV of the royalty stream. Assuming that production occurs uniformly of the life of a well would tend to understate the present value of that production. A better measure would be the average or typical production profile though each actual profile is likely to vary dramatically from the average one. If the Board is considering using lease specific oil and gas prices in its calculation as a move towards accuracy, then it makes no sense to use any of these average methods of estimating NPV.

3) Investigate whether there is additional information that would help strengthen the discussion in the Basis for Conclusions (BfC) regarding the 'reliability' of EIA's estimates of proved reserves.

Members of the Board asked if there is information available that could provide a comparison between reported estimates of proved oil and gas reserves and the actual amounts produced. Staff believes that the following information would be useful to the members in deciding whether an average or specific wellhead price is to be proposed:

a) Are there data available to provide a comparison between reported estimates of proved reserves and the actual amounts produced? If so, please describe the available data, including the degree of totality for all reported estimates of proved reserves under the control of the Federal government and how often it is updated. For example, are there data available to make comparisons for both offshore and onshore estimates of proved reserves? Are the data available to make comparisons for all offshore estimates of proved reserves, or it available for only certain areas, e.g., the Gulf of Mexico area?

Proved reserves estimates are an estimate of the economically recoverable oil and gas resources from known accumulations. Attempting to validate the proved reserve estimate by comparing it to the oil and gas that are ultimately recovered from the accumulation creates several pitfalls. First, one would have to wait until all resources are exhausted which could take many years. Second, proved reserve estimates are continually revised as new information is learned regarding the accumulation until, by the time the resource is exhausted, the reserve estimate equals the volumes of produced resources. Third, proved reserves estimates, especially early ones, are inherently different relative to later estimates and resources ultimately recovered from the accumulation. This is often because the accumulation is not fully delineated and the true extent and producibliity of the resource is not yet known with the confidence necessary to label the entire postulated resource as proved reserves. There is doubt that the data exist to do this exercise historically – for those wells that no longer produce. One option is to theoretically take the production data from wells that are expended and compare that production to the original estimates of proved reserves, but the location or source of this data is unknown at this time And as is pointed out above, those original estimates of proved reserves continually change over time.

b) Please offer an opinion regarding the reliability of the available data.

Reliable production data exist at DOE. DOE states that there data is very reliable.

c) If data are not available to make comparisons, please explain what steps would be needed to obtain the data, including any difficulties and cost.

Explained earlier – have to compare the first estimates to the ultimate well production of those wells that no longer produce.

Department of Energy, Energy Information Administration (EIA), Office of Oil and Gas, Reserves and Production Division

4) Investigate whether there is a method to estimate the net present value of reported proved oil and gas reserves.

At the March 2004 Board meeting, Board members were informed that there is a “rule of thumb” to estimate the net present value of proved reserves -- roughly one third (1/3) of the nominal value of the proved reserves. For example, if the quantity of estimated proved reserves were 9 million barrels and the price per barrel was $20, the net present value of the reserves estimated based on the rule of thumb would be $60 million (9,000,000 X $20 per barrel X 1/3 = $60 million).

Staff believes that the following information would be useful to the members in deciding whether there is a method to calculate a reliable and verifiable net present value for proved oil and gas reserves:

a) A discussion about the elements and methodology used to calculate a net present value for proved oil and gas reserves.

b) A discussion on the use of the proved oil and gas reserves net present vale information.

c) Please offer an opinion regarding the reliability and verifiability of the proved reserves net present value.

5) Please clarify the meaning of the term “adjustments” as it is used in the EIA’s calculation of proved reserves.

The EIA-23, *Annual Survey of Domestic Oil and Gas*, instructions point out that the published reserves estimates include an additional term, adjustments, calculated by the EIA, which preserves an exact annual reserves balance. The instructions explain that 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.

Can you please explain the meanings for the following and generally how often it would occur to require an adjustment to be made:

a) variations caused by changes in the operator frame;

b) different random samples;

c) different timing of reporting;

d) incorrectly reported data; or,

e) imputations for missing or unreported reserve changes can contribute to adjustment.

Department of the Interior

6) Does the MMS discount its budget projections for bonus bids, rents, and royalties to a net present value?

No, all revenue estimates are presented in current dollars.

7) Do bonus bids reflect the economic value of leases to the Federal government?

No, they reflect the value to the high bidder. If this value (high bid) exceeds the lease's value to the Government, it is accepted. The lease's value to the Government is equal to the risked estimate of the residual net present value of a lease after royalties are paid and after an allowed rate of return to the lessee. The estimates are risked because the existence of resources is generally unconfirmed at the time of lease acquisition. Risking is highly variable from tract to tract. Because of the enormous uncertainties surrounding the resource and market conditions, many leases will not be developed or even explored and others that may have been acquired with relatively low bids because of high levels of uncertainty may ultimately produce large amounts at great profit.

That is, are bonus bids on oil and gas leases proportionate to the value of the Federal government's royalty share of proved oil and gas reserves received from the leases?

The proportionality of bonuses to royalties has little, if anything, to do with economic value. While it is true that, everything else being equal, higher royalties implies more value, hence larger bonuses, in practice everything else is not equal, e.g., water depth, drilling depth, distance from shore, expectations vs. realizations, etc.