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September 5, 2008

Ms. Florence Harmon
Acting Secretary
Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549-1090

Re: File Number S7-15-08 – Modernization of the Oil and Gas Reporting Requirements

Dear Ms. Harmon:

Exxon Mobil Corporation would like to express its support for the Commission's project to re-examine the reporting requirements for oil and gas reserves. The reporting of oil and gas reserves is very important to ExxonMobil, our current and prospective shareholders and other users of our financial statements. The Commission's recent rule proposal addresses many important issues that have been long-time concerns to the oil and gas industry. It is clear to us that the staff has been methodical and comprehensive in developing the rule proposal and we appreciate this effort.

We also note that the proposal positively addresses most of the key recommendations which the American Petroleum Institute (API) and ExxonMobil offered on the earlier Concept Release. We are particularly supportive of the proposals to use 12-month average prices to calculate reserves; to allow the inclusion of tar sands and other non-traditional resources in oil and gas reserves; and to revise the recognition threshold for proved undeveloped reserves. We also believe that most of the proposed technical and definitional changes are consistent with the Society of Petroleum Engineers' (SPE) Petroleum Resources Management System (PRMS) for the reporting of proved reserves. We believe this alignment will assist in the acceptance, understanding and implementation of the new rules. We also believe that many of the proposed changes in the reserves recognition guidelines appear to be principles-based in nature and thus will be robust and flexible in addressing future industry technology changes.

ExxonMobil participated in the development of the API comment letter on the rule proposal, which was filed on August 20, 2008. We fully endorse the positions and recommendations in that letter. To further support the API letter, ExxonMobil provides comments in the attachment that address all of the questions posed in the Commission's rule proposal.

As noted in the API letter, ExxonMobil is very concerned about the extensive new disclosure requirements included in the proposal, most of which were not discussed in the Concept Release. The new disclosures are extensive in scope and will require a significant implementation effort, including costly systems changes and retraining of our personnel. The cost-benefit analysis section of the proposal estimates that the new rules will require an incremental effort of 35 hours per registrant. We believe this is significantly understated and that for ExxonMobil the incremental effort will be in the range of 15,000 to 20,000 hours. More importantly, we believe some of the proposed disclosures are of little value to financial statement users, do not justify the high implementation costs and can cause competitive damage to the disclosing company in some instances. We believe these disclosures are contrary to recent Commission efforts to reduce the complexity of the U.S. reporting system.

In analyzing the rule proposal, we noted several common characteristics of the disclosures that cause us the greatest concern. We would encourage the staff to consider these aspects when deliberating on the final rule proposal. We summarize these below and our detailed responses in the attachment expand on these concepts and provide specific recommendations in each area of the rule proposal.

Level of Granularity

Many of the proposed disclosures require a degree of granularity not currently present in our reporting systems and will necessitate costly changes. We believe data disclosures that go beyond what we use to manage the business on a day to day basis are inherently excessive. For example, we believe the proposed segmentation of reserves and drill well data along so many different parameters will significantly increase the length and complexity of the disclosures, while adding little incremental value for investors and financial statement users. We particularly question the value of drill well data to investors and whether it provides any substantial insights to financial statement users in assessing the economic value of a company's operations.

Anti-abuse Measures

From the discussion in the rule proposal, it appears that some of the new disclosures were added as anti-abuse measures. For example, there appears to be a concern that some companies may be too aggressive in adding new reserves under the proposed new definition of "reliable technology" and that additional disclosures would help prevent that. Also, the extensive new disclosures around proved undeveloped reserves (PUDs), including the aging and tracking of PUDs by their year of recognition and the tracking of related investment dollars, seem to be driven by this concern. Similarly, the disclosures of the qualifications of company reserves estimators also seems to be an anti-abuse measure and essentially amounts to a duplicative disclosure and certification for the reserves estimation process versus what is already required under the Sarbanes-Oxley

Act. We believe that disclosures are an ineffective and costly approach to addressing internal control considerations and unnecessarily add to the complexity of the U.S. reporting system. We believe that abuse concerns are more than adequately addressed by the Sarbanes-Oxley compliance systems that companies have implemented at great expense over the last few years.

Bright Line Tests

We also note that many of the proposed disclosures contain bright line tests or definitions that supplant the exercise of management judgment in tailoring disclosures to address the material aspects of a company's business from a management perspective. We believe this approach is inconsistent with the objective of a principles-based disclosure system. Similar to other judgmental accounting or reporting areas, we believe company personnel and management are in the best position to make reasonable judgments about segmentation and level of detail based on their own company's specific facts and circumstances. We also believe that the use of bright line tests potentially requires companies, in some instances, to disclose information that would cause competitive damage. For example, we believe there is a strong potential for competitive damage to companies from some of the requirements to disclose information at the field or basin level. Such disclosures can undermine the negotiating positions of companies in future property sale transactions, unitization agreements or other asset transfers. Also, information about individual fields or basins is sensitive data that is often subject to restrictions by the national governments that have awarded the concession rights. For the above reasons, we strongly recommend that the staff reconsider the use of bright line tests and requirements throughout the rule proposal as these almost always lead to unnecessary complexity and other unintended consequences.

Duplication

In some cases, we believe the proposed disclosures require duplicative work. The key example of this is the proposed requirement for a dual pricing system. As highlighted in the API comment letter, the rule proposal would require reserves to be calculated on two different bases: one using 12-month average prices for reserves disclosure purposes and one using single-day, year-end prices for financial statement accounting purposes. This will effectively double the required amount of record keeping for year-end reporting purposes and is the single costliest feature of the rule proposal. We believe this requirement would break the link between the required reserves disclosures and the underlying financial statement accounting, which we believe is inconsistent with an effective and transparent reporting model. We are not aware of any other area in the accounting literature in which the accounting and the related underlying disclosures are calculated on different bases. We also do not believe that the use of two different pricing bases would add any meaningful value to financial statement users. For these reasons, we strongly recommend that the staff align the accounting and reserves disclosure requirements on the 12-month average price basis in the final rules.

Alignment with FASB

There are several questions in the rule proposal which indicate that the staff believes that the Financial Accounting Standards Board (FASB) may not amend SFAS 19, SFAS 25 and SFAS 69 to conform to the new SEC disclosure rules. This is a potential outcome that would be extremely costly and disappointing to ExxonMobil and the rest of the oil and gas industry. From the standpoint that the FASB derives their authority to set accounting standards from the Commission, we encourage the staff to exercise leadership to ensure that the final rule proposal and the related financial accounting standards are conformed to establish a single consistent regulatory framework. We believe a dual reporting framework and attendant requirements to reconcile differences would be extremely costly to companies and confusing to financial statement users. We also believe such an outcome would be contrary to the Commission's efforts to reduce the complexity of the U.S. financial reporting system.

ExxonMobil appreciates the Commission's efforts to re-examine the reserves disclosure system and to provide companies with an opportunity to comment. Representatives of ExxonMobil would welcome the opportunity to discuss our response with the Commission's staff, or any other questions that the staff may have, as this project progresses.

Sincerely,

cc:	Mr. Glenn Brady	Extractive Activities Research Project, IASB
	Mr. Robert Garnett	IASB
	Mr. George Batavick	FASB

<u>RESPONSES TO QUESTIONS IN SEC RULE PROPOSAL ENTITLED: "MODERNIZATION OF THE OIL AND GAS REPORTING REQUIREMENTS"</u>

II. Revisions and Additions to the Definition Section of Rule 4-10 of Regulation S-X

B. Year-End Pricing

1. 12-month average price

Should the economic producibility of a company's oil and gas reserves be based on a 12-month historical average price? Should we consider an historical average price over a shorter period of time, such as three, six, or nine months? Should we consider a longer period of time, such as two years? If so, why?

We strongly recommend that all reserves disclosures and related accounting be based on the same 12-month average pricing methodology. This approach significantly reduces the impact of short-term price volatility that can arise from the use of single day prices and maintains comparability of disclosures among companies. We believe an average price based on a 12-month period is an appropriate time period to determine the pricing and provides a basis more consistent with the long-term nature of the oil and gas business.

Should we require a different pricing method? Should we require the use of futures prices instead of historical prices? Is there enough information on futures prices and appropriate differentials for all products in all geographic areas to provide sufficient reporting consistency and comparability?

No, we do not recommend the use of a different pricing method. As for the use of futures prices, we believe that the futures markets in many geographic areas lack the breadth and depth of activity that will be required to support such an approach. If futures were the reporting basis, we anticipate that company estimates will be required to address the lack of futures market prices or futures market prices in thinly traded markets that were believed to be non-representative. We believe that the resulting reserves reporting will have an unacceptable degree of inconsistency and lack of comparability between companies.

Should the average price be calculated based on the prices on the last day of each month during the 12-month period, as proposed? Is there another method to calculate the price that would be more representative of the 12-month average, such as prices on the first day of each month? Why would such a method be preferable?

Consistent with the earlier API recommendations on the Concept Release, we continue to believe that the 12-month period should run from October 1 of the previous year to September 30 of the reporting year for companies with a fiscal year ending on December 31. We would alternatively recommend that the staff consider changing the 12-month average price to an average of first-of-the-month prices, ending with December 1 for a calendar year company. This will achieve the desired averaging effect and will align with the fiscal year for accounting purposes. It will also help preparers in managing their heavy year-end workloads by providing an additional 30 days to calculate reserves versus the current disclosure requirements. As noted in the API comment letter, many industry companies have indicated that they believe first-of-the-month pricing is preferable for use in the 12-month average price calculation as month-end market prices are more subject to unusual daily price volatility from the close-out of trading positions and other month-end trading activities.

Should we require, rather than merely permit, disclosure based on several different pricing methods? If so, which different methods should we require?

We strongly recommend the use of one consistent pricing basis for all companies. As indicated above, we believe the single price basis should be a 12-month historical average price. Requiring disclosures on several different pricing bases will necessitate costly system and business process changes by preparers without achieving added benefits for users of financial statements. To the contrary, we believe the use of multiple pricing bases will confuse financial statement users and will likely require additional disclosures to explain the differences.

Should we require a different price, or supplemental disclosure, if circumstances indicate a consistent trend in prices, such as if prices at year-end are materially above or below the average price for that year? If so, should we specify the particular circumstances that would trigger such disclosure, such as a 10%, 20%, or 30% differential between the average price and the year-end price? If so, what circumstances should we specify?

We do not believe that the use of different prices or the use of supplemental disclosures should be required if year-end prices are different than the average price for that year. The rationale for utilizing average prices is to reduce price volatility associated with prices at a single point in time and to provide a price which is more reflective of the long-term nature of the upstream business. We believe that requiring the use of different prices or the use of supplemental disclosures will undermine the benefits gained from using average prices and re-introduce unnecessary price volatility. If a consistent and significantly different price trend emerges which could materially change the determination of a preparer's proved reserves in future periods, the preparer could disclose the situation and its potential impact.

2. Trailing year-end

Should the price used to determine the economic producibility of oil and gas reserves be based on a time period other than the fiscal year, as some commenters have suggested? If so, how would such pricing be useful? Would the use of a pricing period other than the fiscal year be misleading to investors? Is a lag time between the close of the pricing period and the end of the company's fiscal year necessary? If so, should the pricing period close one month, two months, three months, or more before the end of the fiscal year? Explain why a particular lag time is preferable or necessary. Do accelerated filing deadlines for the periodic reports of larger companies justify using a pricing period ending before the fiscal year end?

Although we strongly support the use of a 12-month average price, requiring the calculation to be based on month-end prices over the reporting year will make it difficult for companies to calculate their reserves in time to meet the 60-day filing deadline for the Annual Report on Form 10-K. For a calendar year company, the requirement to use month-end prices means that reserves estimating work can not effectively commence until the December 31st price is finalized. Consistent with the earlier API recommendations on the Concept Release, we continue to believe that the 12-month period should run from October 1 of the previous year to September 30 of the reporting year for companies with a fiscal year ending on December 31. We would alternatively suggest that the staff consider changing the 12-month average price to an average of first-of-the-month prices, ending with December 1 for a calendar year company. We believe the use of first-of-the-month prices as an alternative will achieve the desired averaging effect and will align with each registrant's fiscal year for accounting purposes, while also allowing preparers 30 additional days of time to complete reserves estimates. We do not see any significant disadvantages with utilizing first-of-the-month prices versus month-end prices.

3. Prices used for accounting purposes

Should we require companies to use the same prices for accounting purposes as for disclosure outside of the financial statements?

We strongly recommend that companies be required to use the same pricing basis for the disclosure of reserves quantities and for the related financial accounting under SFAS 19 (primarily the calculation of unit-of-production depreciation and depletion rates). The use of two pricing bases will sever the link between the required disclosures and the related financial accounting which is not consistent with an effective and transparent reporting model.

As noted in our subsequent responses, we do not believe that the use of average prices for accounting purposes will create material differences in unit-of-production depreciation expense from period to period versus the use of year-end prices. To the contrary, the use of average prices will reduce the magnitude of changes that may otherwise be caused by large fluctuations in year-end prices. In any event, we do not think that depreciation expense based on single-day, year-end prices yields a conceptually better accounting result than one based on average prices. Therefore, we believe that the use of two different pricing bases will not add any meaningful value to financial statement users but would certainly place a significant new burden on registrants. For these reasons, we strongly recommend that the accounting and disclosure requirements be aligned on the 12-month average price basis.

Is there a basis to continue to treat companies using the full cost accounting method differently from companies using the successful efforts accounting method? For example, should we require, or allow, a company using the successful efforts accounting method to use an average price but require companies using the full cost accounting method to use a single-day, year-end price?

Should we require companies using the full cost accounting method to use a single-day, year-end price to calculate the limitation on capitalized costs under that accounting method, as proposed? If such a company were to use an average price and prices are higher than the average at year end or at the time the company issues its financial statements, should that company be required to record an impairment charge?

We believe that all companies subject to Regulation S-X and SFAS 19 and SFAS 69 should use the same price basis for calculating proved reserves. We believe the comparability of reported reserves between all companies is improved, and hence the overall financial reporting system is improved, if all reserves calculations are based on the same consistent price basis.

As to the specific issue of accounting by full cost companies, we believe the Commission should consider modifying Regulation S-X, Rule 4-10 to require full cost companies to calculate impairment charges using the same 12-month average price that will be used for reserves estimates. The arguments for this approach are essentially the same as the ones made for basing proved reserves on 12-month average prices versus single-day, year-end prices. This approach significantly reduces the impact of short-term price volatility that can arise from the use of single day prices, is more consistent with the long-term nature of the oil and gas business and aligns the accounting with the related disclosures. If the prices in effect at year-end are significantly different than the 12-month average prices, a full cost company could disclose this fact as well as the estimated impact of any potential impairment charges should the price trend persist during the ensuing accounting period.

Should the disclosures required by SFAS 69 be prepared based on different prices than the disclosures required by proposed Section 1200?

We strongly recommend that all proved reserves disclosures be based on the same 12-month average pricing methodology, including all SFAS 69 disclosures and calculations.

If proved reserves, for purposes of disclosure outside of the financial statements, other than supplemental information provided pursuant to SFAS 69, are defined differently from reserves for purposes of determining depreciation, should we require disclosure of that fact, including quantification of the difference, if the effect on depreciation is material?

What concerns would be raised by rules that require the use of different prices for accounting and disclosure purposes? For example, is it consistent to use an average price to estimate the amount of reserves, but then apply a single-day price to calculate the ceiling test under the full cost accounting method? Would companies have sufficient time to prepare separate reserves estimates for purposes of reserves disclosure on one hand, and calculation of depreciation on the other? Would such a requirement impose an unnecessary burden on companies?

We recommend the implementation of the same 12-month average pricing methodology for both reserves disclosures and for accounting purposes. We believe the use of a different methodology (such as year-end prices) for determining SFAS 19 depreciation amounts will be unduly costly and burdensome to registrants, confusing to financial statement users, and inconsistent with an effective and transparent reporting model for oil and gas companies. At the same time, however, if a different basis was used for determining proved reserve quantities for SFAS 19 depreciation calculations, we believe it is unlikely that the resultant impact on depreciation provisions will be significant enough to require disclosure. The fact that full cost companies might be in a situation where their disclosed reserves are based on year-average prices but their ceiling test calculations (and possible impairment charges) are based on a single year-end price is inherently inconsistent. In our opinion, this is another good reason to establish a 12-month average pricing methodology for all accounting purposes.

Will our proposed change to the definitions of proved reserves and proved developed reserves for accounting purposes have an impact on current depreciation amounts or net income and to what degree?

In view of the typical relationship between the amount of proved reserves and the attendant volume of production during any one accounting period, and our view of the potential changes to proved reserves and proved developed reserves, we believe it is very unlikely that the proposed changes to the reserves definitions will have a material impact on unit-of-production depreciation expense or net income at the time of transition or in subsequent accounting periods.

If we change the definitions of proved reserves and proved developed reserves to use average pricing for accounting purposes, what would be the impact of that change on current depreciation amounts and on the ceiling test? Would the differences be significant?

Similar to our response above, we do not believe that a change to average pricing for accounting purposes will create material changes in unit-of-production depreciation expenses or net income at the time of transition or in subsequent accounting periods. We also do not think it will have a material impact on the application of the ceiling test by full cost companies. To the contrary, the use of average prices will reduce the magnitude of changes that may otherwise be caused by large fluctuations in year-end prices.

In any event, we do not think that depreciation expense based on single-day, year-end prices yields a conceptually better accounting result than one based on average prices. Therefore, we believe that the use of two different pricing bases will not add any meaningful value to financial statement users while placing a significant new burden on registrants. For these reasons, we strongly recommend that the accounting and disclosure requirements be aligned on the 12-month average price basis.

C. Extraction of Bitumen and Other Non-Traditional Resources

Should we consider the extraction of bitumen from oil sands, extraction of synthetic oil from oil shales, and production of natural gas and synthetic oil and gas from coalbeds to be considered oil and gas producing activities, as proposed? Are there other non-traditional resources whose extraction should be considered oil and gas producing activities? If so, why?

Yes, we strongly support recognizing the listed activities as oil and gas producing activities. We also strongly support the proposed rule changes which will shift the focus of the definition of oil and gas producing activities to the final product of such activities, regardless of the extraction technology used. If the final product of the activity results in oil or gas similar to that from a "traditional" producing well, then it should be considered an oil and gas activity. We believe this same principle should apply to any future non-traditional resources not specifically enumerated in the rule proposal. This approach will make the rules flexible and robust in addressing future unconventional resources, consistent with a principles-based system.

The extraction of coal raises issues because it is most often used directly as mined fuel, although hydrocarbons can be extracted from it. As noted above, we propose to include the extraction of coalbed methane as an oil and gas producing activity. However, the actual mining of coal has traditionally been viewed as a mining activity. In most cases, extracted coal is used as feedstock for energy production rather than refined further to extract hydrocarbons.

However, as technologies progress, certain processes to extract hydrocarbons from extracted coal, such as coal gasification, may become more prevalent. Applying rules to coal based on the ultimate use of the resource could lead to different disclosure and accounting implications for similar coal mining companies based solely on the coal's end use. How should we address these concerns? Should all coal extraction be considered an oil and gas producing activity? Should it all be considered mining activity? Should the treatment be based on the end use of the coal? Please provide a detailed explanation for your comments.

The same principle stated in the previous response should apply to coal extraction, i.e. the treatment should be based on the final product produced. If the coal is gasified, then the gas produced will be included with other natural gas reserves. Consistent with this approach, it is possible that a company could have different disclosure requirements depending on the end use of the coal. We believe this approach is sensible as the investment decisions made by the company for each mode of operation will be based on the value and disposition of the end products produced and will be evaluated against alternative investments for producing the same products from traditional mining or oil and gas producing activities.

Similar issues could arise regarding oil shales, although to a significantly less extent, because those resources currently are used as direct fuel only in limited applications. How should we treat the extraction of oil shales?

Consistent with a principles-based disclosure system, we believe the same logic from our previous response should apply to the extraction of oil shales.

If adopted, how would the proposed changes affect the financial statements of producers of non-traditional resources and mining producers?

These changes will not have a significant impact on ExxonMobil's financial statements and we believe the impact will be similar for other oil and gas companies. For example, the operating results for the extraction of bitumen from oil sands is already reported in the "Upstream" financial segment, so there will be no change in financial statement segmentation. For SFAS 69 Supplemental Oil and Gas reporting, the oil sands data currently shown as mining will be added to the traditional oil and gas data. We believe this will greatly improve the quality and completeness of industry financial reporting practices as it will present upstream operations to investors and other financial statement users on the same basis that company management views such operations. The investment community also views hydrocarbons produced from such resources as an integral part of the upstream oil and gas production business.

D. Reasonable Certainty and Proved Oil and Gas Reserves

Is the proposed definition of "reasonable certainty" as "much more likely to be achieved than not" a clear standard? Is the standard in the proposed definition appropriate? Would a different standard be more appropriate?

Is the proposed 90% threshold appropriate for defining reasonable certainty when probabilistic methods are used? Should we use another percentage value? If so, what value?

We believe that most constituents in the reserves reporting process, including companies, investors, financial statement users and regulators, have a good understanding of the concept of reasonable certainty. While we believe the proposed definitional change clarifies the meaning of "reasonable certainty" in a manner that is consistent with the common industry understanding of the term, we suggest that the staff consider using the SPE PRMS definition instead. The PRMS definition of "reasonable certainty" is a "high degree of confidence that quantities would be produced." We believe the two definitions are essentially equivalent and neither change the level of certainty required to recognize proved reserves. However, we believe that alignment of the definitions with the PRMS wherever possible will assist in the acceptance, understanding and implementation of the new rules as the PRMS is the most widely accepted benchmark for classifying reserves in the global energy industry.

Likewise, we support the proposed 90% probability threshold for proved reserves when probabilistic methods are used. This has been a common convention used in other reporting systems and is aligned with the SPE PRMS.

1. New technology

Is our proposed definition of "reliable technology" appropriate? Should we change any of its proposed criteria, such as widespread acceptance, consistency, or 90% reliability?

We believe that the proposed addition of the "reliable technology" definition to Rule 4-10 is consistent with a principles-based approach and will enhance and increase the consistency of reserves reporting in accordance with the "reasonable certainty" criteria. We believe the proposed criteria are all appropriate.

We support the proposed criteria for establishing "reliable technology." However, there may be cases where proprietary technology or technology using proprietary data has been demonstrated to be highly reliable, but is not widely available for general use by industry and therefore does not have "widespread acceptance." We recommend that the proposed definition of "reliable technology" be broadened to include these cases.

Is the open-ended type of definition of "reliable technology" that we propose appropriate? Would permitting the company to determine which technologies to use to determine their reserves estimates be subject to abuse? Do investors have the capacity to distinguish whether a particular technology is reasonable for use in a particular situation? What are the risks associated with adoption of such a definition?

We believe that the proposed definition is appropriate since it provides the flexibility and scope to include new technologies as they are developed and demonstrated to be reliable. Similar to other judgmental accounting or reporting areas, we believe that company personnel and management are in the best position to make reasonable judgments based on their own company's specific facts, technologies and circumstances. Abuse prevention should be adequately handled by the existing requirements for companies to have in place effective systems of internal controls. We do not believe that investors are generally in the best position to determine whether the use of a specific technology was appropriate for a particular situation. Such determination requires specialized knowledge and technical expertise that investors typically would not have.

Is the proposed disclosure of the technology used to establish the appropriate level of certainty for material properties in a company's first filing with the Commission and for material additions to reserves estimates in subsequent filings appropriate? Should we require disclosure of the technology used for all properties? Should we require companies currently filing reports with the Commission to disclose the technology used to establish appropriate levels of certainty regarding their currently disclosed reserves estimates?

We believe the proposed disclosures are not appropriate. It is very difficult to assess the specific contribution that a particular technology may make to a reserves estimate. Multiple technologies are typically used together and the strengths of each are used to yield the most accurate result. Our perspective is that experience, sound professional judgment and process consistency are the key factors in determining reasonable certainty and may be more significant in the determination of the relative certainty of reserve estimates rather than specific technologies. Since experience and professional judgment are very difficult to quantify, we believe that this should not be a disclosure requirement. Moreover, implementing additional processes and controls in order to disclose the "technical methods" will be time-consuming and costly. It is unlikely that this information will provide any benefit to the typical investor or other financial statement user, since its use requires specialized knowledge and technical expertise. The requirement for disclosure of the technologies used could also cause competitive harm given their proprietary nature.

2. Probabilistic methods

Are the proposed definitions of "deterministic estimate" and "probabilistic estimate" appropriate? Should we revise either of these definitions in any way? If so, how?

Are the statements regarding the use of deterministic and probabilistic estimates in the proposed definition of "reasonable certainty" appropriate? Should we change them in any way? If so, how?

We believe the proposed definitions of "deterministic estimate" and "probabilistic estimate" are clear and appropriate. The statements added to the definitions will improve their clarity and acceptance as these are concepts with which the industry is very familiar.

Should an oil and gas company have the choice of using deterministic or probabilistic methods for reserves estimation, or should we require one method? If we were to require a single method, which one should it be? Why? Would there be greater comparability between companies if only one method was used?

The selection of assessment methodology for reserves estimation should be at the discretion of companies as both are technically acceptable methods. However, if only a single methodology is to be allowed, the deterministic approach should be selected as it has been the long held industry standard and will be the method most understood by company reserves estimators, financial statement users and regulators. Given the importance of technical and professional judgment in the estimation of reserves, we do not believe the selection of a single method will necessarily improve the comparability of reserves estimation practices between companies.

Should we require companies to disclose whether they use deterministic or probabilistic methods for their reserves estimates?

No, we believe such disclosures should be at the option of each company. Regardless of the methodology selected, companies will still be required to achieve the appropriate level of reasonable certainty to justify the recognition of reserves.

3. Other revisions related to proved oil and gas reserves

Should we permit the use of technologies that do not provide direct information on fluid contacts to establish reservoir fluid contacts, provided that they meet the definition of "reliable technology," as proposed?

Yes, we believe such technologies should be allowed, provided that they meet the definition of "reliable technology." We believe this approach is consistent with a principles-based disclosure system. As we have indicated in other responses, we believe that the reserves estimation process is highly dependent on the application of good management and technical judgment to ensure that the standard of reasonable certainty is obtained for the recognition of proved reserves. We believe a given technology may be "reliable" and appropriate to use in one case, but may not be appropriate for all cases. Use of a particular technology, whether it is to determine reservoir fluid contacts, reservoir continuity, or other reserves parameters, needs to be evaluated and utilized as appropriate on a case by case basis.

Should there be other requirements to establish that reserves are proved? For example, for a project to be reasonably certain of implementation, is it necessary for the issuer to demonstrate either that it will be able to finance the project from internal cash flow or that it has secured external financing?

Consistent with our prior response, we believe the principle of "reasonable certainty" should be applicable to all aspects of the reserves recovery process, including financial, commercial and project execution aspects, in addition to the geoscience considerations. Thus, instead of incorporating lists of specific requirements or other bright line tests into the rules, we believe that the evaluation of each aspect should depend on the application of good management and technical judgment, supported by each company's internal control and management certification processes.

E. Unproved Reserves – "Probable Reserves" and "Possible Reserves"

Should we permit a company to disclose its probable or possible reserves, as proposed? If so, why?

We strongly prefer that reserves reporting be limited to proved reserves only as prescribed by the current disclosure requirements. However, we view the proposed optional reporting of probable and possible reserves as an acceptable alternative to mandatory reporting of such reserves in documents filed with the SEC. Any company who chooses to disclose such reserves in their 10-K will need to ensure that they comply with the SEC definitions and methodologies (which are consistent with the SPE PRMS) and be willing to accept a higher risk of additional, unwarranted litigation due to the inherent uncertainty associated with these reserves.

Should we require, rather than permit, disclosure of probable or possible reserves? If so, why?

We believe it is critical that the Commission not require the disclosure of probable or possible reserves in filed documents. Financial statement users will not be well served by the mandated inclusion of such resources due to their increased uncertainty and the breadth of methodologies and evaluation techniques that may be employed in their calculation. We also believe that such reporting could expose companies to additional, unwarranted litigation due to their increased uncertainty.

Should we adopt the proposed definitions of probable reserves and possible reserves?

Should we make any revisions to those proposed definitions? If so, how should we revise them?

The proposed definitions of probable and possible reserves, which broadly conform to PRMS guidelines, are acceptable for companies which elect to report such reserves in their filed documents. However, the SEC should not mandate the use of PRMS methodology if companies choose to disclose probable and possible quantities in public forums other than documents filed with the SEC.

Are the proposed 50% and 10% probability thresholds appropriate for estimating probable and possible reserves quantities when a company uses probabilistic methods? Should probable reserves have a 60% or 70% probability threshold? Should possible reserves have a 15% or 20% probability threshold? If not, how should we modify them?

The proposed 50% and 10% probability thresholds are consistent with the PRMS methodology and are acceptable provided they are limited to the optional reporting of probable or possible reserves in documents filed with the Commission.

F. Definition of "Proved Developed Oil and Gas Reserves"

Should we revise the definition of proved developed oil and gas reserves, as proposed? Should we make any other revisions to that definition? If so, how should we revise it?

The proposed definition of proved developed oil and gas reserves is acceptable, since it now covers extraction of resources using technologies other than production through wells. We do not recommend any changes to the rule proposal in this area.

G. Definition of "Proved Undeveloped Reserves"

1. Proposed replacement of certainty threshold

Are the proposed revisions appropriate? Would the proposed expansion of the PUDs definition create potential for abuses?

Should we replace the current "certainty" threshold for reserves in drilling units beyond immediately adjacent drilling units with a "reasonable certainty" threshold as proposed?

Is it appropriate to prohibit a company from assigning proved status to undrilled locations if the locations are not scheduled to be drilled more than five years, absent unusual circumstances, as proposed? Should the proposed time period be shorter or longer than five years? Should it be three years? Should it be longer, such as seven or ten years?

We believe changing the recognition threshold for PUDs to "reasonable certainty" and allowing the use of "reliable technology" to support their recognition are appropriate changes that will modernize the disclosure system. The changes will improve the internal consistency of the guidelines by establishing one recognition threshold (i.e., reasonable certainty, reliable technology) for all categories of proved reserves. These changes will also make the rules more consistent with a principles-based system by facilitating the application of professional judgment and the application of new technologies as they evolve.

However, we believe the introduction of a "bright line" test for recognizing PUDs that will not be drilled within five years is unduly restrictive and should be deleted. We believe that the recognition of PUDs should continue to be based on management's comprehensive assessment of the geoscience, financial, commercial and operational aspects of each development project utilizing the standard of reasonable certainty. In the case of PUDs, recognition will be particularly dependent on management's firm commitment to develop the reserves over the project's anticipated time horizon. Given the increasing scale and life of industry development projects, we believe the proposed five-year test (or any other "bright line" test) will apply to an increasingly significant percentage of projects and related reserves and, therefore, will not be "unusual" in occurrence as the rule proposal seems to anticipate. Consequently, this additional test will significantly add to the new disclosure burden created by the overall rule proposal.

We strongly recommend that the staff avoid the use of arbitrary time deadlines or other bright line tests throughout the final rule proposal as these will be inconsistent with a principles-based regime. We do not believe that the proposed changes to the PUDs definition, or for that matter any of the other proposed rule changes, increase the risk of abuse. We believe that abuse prevention is adequately addressed by the extensive Sarbanes-Oxley rules that require companies to have in place an effective system of internal controls over their financial reporting and disclosure systems, which includes the reserves reporting process.

Should the proposed definition specify the types of unusual circumstances that would justify a development schedule longer than five years for reserves that are classified as proved undeveloped reserves?

Consistent with our previous response, we discourage the creation of detailed check lists or other bright line tests. In this case, we believe it will be difficult to create a comprehensive list of "unusual circumstances" that could occur now or that may occur in the future as the industry continues to evolve. Each case would need to be considered on its own merits.

2. Proposed definitions for continuous and conventional accumulations

Should we provide separate definitions of conventional and continuous accumulations, as proposed? Would separate disclosure of these accumulations be helpful to investors?

No, we do not believe that separate definitions or disclosures of conventional and continuous accumulations are needed. We believe the disclosures should continue to be differentiated by end-product (i.e. oil and gas) rather than the type of accumulation. We recommend that proposed segmentation by conventional and continuous accumulations be eliminated as we believe this split will be of limited value to financial statement users.

Should we revise our proposed definition of "continuous accumulations" in any way? For example, should the proposed definition provide examples of such accumulations? If so, how should we revise it?

As stated in the previous response, we do not believe this definition is needed and should be eliminated in its entirety.

Should we revise our proposed definition of "conventional accumulations" in any way? If so, how should we revise it?

As stated in the previous response, we do not believe this definition is needed and should be eliminated in its entirety.

3. Proposed treatment of improved recovery projects

Should we expand the definition of proved undeveloped reserves to permit the use of techniques that have been proven effective by actual production from projects in an analogous reservoir in the same geologic formation in the immediate area or by other evidence using reliable technology that establishes reasonable certainty?

We strongly support the expansion of the definition of proved undeveloped reserves to allow the use of "reliable technology" to establish reasonable certainty of improved recovery. Consistent with the SPE PRMS (2.3.4 Improved Recovery), we recommend the proposed analog description be changed to "a reservoir with analogous rock and fluid properties where a similar established improved recovery project has been successfully applied." This change will make the rules more consistent with a principles-based approach and better allow the application of professional judgment and the use of new technologies as they evolve.

H. Proposed Definition of Reserves

Is the proposed definition of "reserves" appropriate? Should we change it in any way? If so, how?

We generally agree with the proposed definition as it is broadly consistent with the SPE PRMS and current industry application. However there are several aspects which we recommend be clarified in the final rule proposal to avoid confusion and/or potential conflicts with other rules and standards.

The term "legal right to produce" has the potential to exclude many economic interests allowed under existing regulations such as royalty interests. We recommend this requirement be changed to "the legal right to produce, a revenue interest in the production, or other non-operating interest."

The term *"current prices and costs"* should be further described to be consistent with the 12-month average pricing proposed elsewhere in the rule proposal.

The determination of the boundary lines around oil and gas production operations is an important feature of the disclosure rules. We believe the proposed definition in the rule proposal omits some well-established guidance found in the existing rules. Accordingly, we recommend that the definition of the oil and gas production function shown in Instruction 1 to paragraph (a)(16)(i)(a) be replaced with the current definition in Regulation SX 4-10 (1)(c) and FASB 19:

> "For purposes of this section, the oil and gas production function shall normally be regarded as terminating at the outlet valve on the lease or field storage tank; if unusual physical or operational circumstances exist, it may be appropriate to regard the production functions as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal."

We also believe that the definition would be improved if it recognized that oil and gas are fungible commodities and that all in-place hydrocarbons ultimately sold or consumed for beneficial use (e.g. fuel gas) should be included in reported reserves.

I. Other Proposed Definitions and Reorganization of Definitions

Are these additional proposed definitions appropriate? Should we revise them in any way?

Are there other terms that we have used in the proposal that need to be defined? If so, which terms and how should we define them?

The additional definitions are appropriate, appear to be comprehensive and will provide helpful guidance. We suggest that the staff also consider the inclusion of the PRMS Glossary (Appendix A) "Glossary of Terms Used in Resources Evaluations."

Should we alphabetize the definitions, as proposed? Would any undue confusion result from the re-ordering of existing definitions?

ExxonMobil supports the proposal to alphabetize the definitions and does not believe that it will result in any confusion.

III. Proposed Amendments to Codify the Oil and Gas Disclosure Requirements in Regulation S-K

A. Proposed Revisions to Item 102, 801, and 802 of Regulation S-K

Is the proposed amendment to Instruction 3, limiting it to extractive activities other than oil and gas activities, appropriate? Should we simply call them mining activities?

Yes, we believe limiting Instruction 3 to extractive activities other than oil and gas activities is appropriate. Since the oil and gas activities will no longer be included, we believe calling them mining activities will be more descriptive and will simplify the guidelines.

Are there any other aspects of Item 102 that we should revise? If so, what are they and how should they be revised?

No, we do not believe any other aspects of Item 102 need to be revised.

B. Proposed New Subpart 1200 of Regulation S-K Codifying Industry Guide 2 Regarding Disclosures by Companies Engaged in Oil and Gas Producing Activities

1. Overview

2. Proposed Item 1201 (General instructions to oil and gas industry-specific disclosures)

Are the proposed general instructions to Subpart 1200 clear and appropriate? Are there any other general instructions that we should include in this proposed Item?

Yes, we believe the proposed instructions to subpart 1200 are clear and that no other general instructions need to be added.

For disclosure items requiring tabulated information, should we require companies to adhere to a specified tabular format, instead of permitting companies to reorganize, supplement, or combine the tables?

No, we do not believe companies should be required to adhere to a specified tabular format. We believe that companies should be permitted the flexibility to present the required data and any supplemental data in a format that is most relevant and meaningful to its operations. This approach is consistent with a principles-based disclosure system.

In particular, should we permit a company to disclose reserves estimates from conventional accumulations in the same table as it discloses its reserves estimates from continuous accumulations?

As discussed in previous responses, we do not believe that separate definitions of conventional and continuous accumulations are needed. We believe the disclosures should continue to be differentiated by end-product (i.e. oil and gas) rather than the type of accumulation. We recommend that the staff eliminate the proposed segmentation by conventional and continuous accumulations as we believe this split will be of limited value to financial statement users and greatly increases the complexity of the required disclosures. If the staff continues to believe that such segmentation is warranted, we believe companies should be permitted to disclose reserves estimates from both conventional and continuous accumulations in the same table.

3. Proposed Item 1202 (Disclosure of reserves)

i. Oil and gas reserves tables

Should we permit companies to disclose their probable reserves or possible reserves? Is the probable reserves category, the possible reserves category (or *both categories) too uncertain to be included as disclosure in a company's public filings? Should we only permit disclosure of probable reserves? What are the advantages and disadvantages of permitting disclosure of probable and possible reserves, from the perspective of both an oil and gas company and an investor in an oil and gas company that chooses to provide such disclosure? Would investors be concerned by such disclosure? Would they understand the risks involved with probable of possible reserves?*

We continue to recommend that the reporting of reserves be limited to proved reserves only. However, the proposed optional reporting of probable and possible reserves is an acceptable alternative to mandatory reporting. We believe that investors would not be well served by the mandated inclusion of probable and possible reserves due to their increased uncertainty. We believe that most investors do not have a sufficient technical understanding of the industry and of the reserves estimation process to appropriately distinguish and appreciate the risks inherent in each category of reserves. We also believe the breadth of methodologies and evaluation techniques that may be employed in the calculation of probable and possible reserves will likely lead to a lack of consistency in industry reporting. We also strongly believe that the reporting of such reserves could expose companies to additional, unwarranted litigation due to their increased risk and uncertainty.

Would the proposed disclosure requirements provide sufficient disclosure for investors to understand how companies classified their reserves? Should the proposed Item require more disclosure regarding the technologies used to establish certainty levels and assumptions made to determine the reserves estimates for each classification?

Should companies be required to provide risk factor disclosure regarding the relative uncertainty associated with the estimation of probable and possible reserves?

As indicated in our previous response, we do not believe that most investors have a sufficient technical understanding of the industry and of the reserves estimation process to appropriately distinguish and appreciate the uncertainty inherent in each category of reserves. We do not think this can be addressed by extensive technical disclosures of the technologies used to support reserves estimates. We believe such a requirement will be impractical to implement since the recognition of reserves is typically based on the use of multiple technologies, data sources and interpretation methods and that such disclosures would be so complex and cumbersome to be of little value to even the most sophisticated investors.

Should we allow filers to report sums of proved and probable reserves or sums of proved, probable, and possible reserves? Or, to avoid misleading investors, *should we allow only disclosure of each category of reserves by itself and not in sum with others, as proposed?*

Given the different uncertainties inherent in each category of reserves, we think that summation of the reserves categories for disclosure purposes could be misleading to investors and should not be allowed.

Should we require disclosure of probable or possible reserves estimates in a company's public filings if that company otherwise discloses such estimates outside of its filings?

No, we strongly oppose such a requirement as it will defeat the objective of optional reporting. It will likely result in a reduction of industry information that is publicly available to financial statement users as we believe most companies will discontinue disclosures in non-filed documents (which is the current practice of many companies) to avoid the increased risk of litigation from mandatory reporting in filed documents. To avoid any confusion vis-à-vis other existing reporting requirements, we believe it would be very helpful for the staff to clarify in the final rule proposal that not using the option to report such reserves in documents filed with the Commission does not preclude companies from continuing to disclose such information in non-filed documents.

Should we require all reported reserves to be simple arithmetic sums of all estimates, as proposed? Alternatively, should we allow probabilistic aggregation of reserves estimated probabilistically up to the company level? If we do so, will company reserves estimated and aggregated deterministically be comparable to company reserves estimated and aggregated probabilistically?

We support the proposed aggregation of estimates as arithmetic sums at the lease, field or project level. We do not believe that segregation of reserves between those estimated probabilistically and those estimated deterministically is warranted since both estimating processes must meet the standard of reasonable certainty before reserves can be recognized. Segmentation of the data by estimating methodology will be burdensome to preparers and of limited value to most investors and financial statement users due to their lack of technical understanding of the industry and the reserves estimation process. When probabilistic methods are used, aggregation beyond the lease, field or project level up to the company level could yield very different results than if the deterministic results were aggregated.

Should we revise the proposed form and content of the table? If so, how should we revise the table's form or content?

With the exception of the proposed geographic segmentation (addressed below), we believe the form and content of the table is appropriate. However, as indicated previously, we believe that companies should be permitted the flexibility to present the required data and any supplemental data in a format that is most relevant and meaningful to its operations. The tabular formats should not be rigid specifications. This approach will be consistent with a principles-based disclosure system.

Should we eliminate the current exception regarding the disclosure of estimates of resources in the context of an acquisition, merger, or consolidation if the company previously provided those estimates to a person that is offering to acquire, merge, or consolidate with the company or otherwise to acquire the company's securities? If so, would this create a significant imbalance in the disclosures being made to the possible acquirer, as opposed to the company's shareholders?

We believe the current option for companies to disclose reserves estimates related to an acquisition, merger or consolidation should be retained as proposed. We believe this allows companies an option to keep shareholders appropriately informed about such transactions and not disadvantaged vis-à-vis the information provided to a possible acquirer.

ii. Optional reserves sensitivity analysis table

Should we adopt such an optional reserves sensitivity analysis table? Would such a table be beneficial to investors? Is such a table necessary or appropriate?

We do not take exception to the proposed optional reserves sensitivity analysis table. However, we do not expect that we will avail ourselves of this option as we do not believe it is cost benefit justified. Calculation of reserves on multiple price bases would greatly expand the workload of our reserves estimators, who are already fully occupied with meeting the 60-day filing deadline for the Annual Report on Form 10-K.

Should we require a sensitivity analysis if there has been a significant decline in prices at the end of the year? If so, should we specify a certain percentage decline that would trigger such disclosure?

No, as noted above, we do not believe that such sensitivity analyses are cost benefit justified. We do not believe that they should be made mandatory under any circumstances.

Should we revise the proposed form and content of the table? If so, how should we revise the table's form or content?

We have no recommendations on the form and content of the table other than it remains an optional election for each company.

As noted above in this release, SFAS 69 currently uses single-day, yearend prices to estimate reserves, while the reserves estimates in the proposed tables would be based on 12-month average year-end prices. If the FASB elects not to change its SFAS 69 disclosures to be based on 12-month average year-end prices, should we require reconciliation between the proposed Item 1202 disclosures and the SFAS 69 disclosures? What other means should we adopt to promote comparability between these disclosures?

The potential outcome described in this question would be extremely costly and disappointing to the industry. From the standpoint that the FASB derives their authority to set accounting standards from the Commission, we encourage the staff to exercise leadership to ensure that the final rule proposal and the related financial accounting standards are conformed to establish a single consistent regulatory framework. We believe a dual reporting framework based on different price assumptions would be extremely costly to companies and confusing to financial statement users. We also believe such an outcome would be contrary to other Commission efforts underway to reduce the complexity of the U.S. financial reporting system.

A dual disclosure system would double the required amount of record keeping and reporting and would severely task our staff, systems and governance processes, which already are fully occupied with meeting the 60-day filing deadline for the Annual Report on Form 10-K. The complexity and cost of this outcome would be increased by a requirement to reconcile the proposed Item 1202 disclosures and the SFAS 69 disclosures.

iii. Geographic specificity with respect to reserves disclosures

Should we provide the proposed guidance about the level of specificity required when a company discloses its oil and gas reserves by "geographic area"?

No, we do not believe that the proposed guidance is warranted and strongly recommend that the Commission retain the current approach specified in SFAS 69. We strongly recommend that the Commission avoid the use of bright line tests and requirements throughout the rule proposal as these almost always lead to unnecessary complexity and are inconsistent with a principles-based regime.

We believe the current requirement in SFAS 69 has worked well, i.e., that reserves be separately disclosed for a company's home country and for such "individual countries or groups of countries as appropriate for meaningful disclosure in the circumstances." We believe this is a principles-based approach that allows each company to determine what represents a "meaningful disclosure" based on a holistic assessment of their specific circumstances. This approach recognizes that geographic location is only one element among many considered in determining risks associated with particular resources. We believe additional segmentation, based solely on arbitrary percentages, will not provide meaningful benefits to financial statement users while increasing costs for preparers. More importantly, we believe the proposed segmentation poses competitive risks which we comment on further below.

We also note that, as proposed, the revised definition will have application far beyond the reporting of proved reserves. The same geographic splits will also apply to the following disclosures:

- Item 1204 – Oil and Gas Production
- Item 1205 – Drilling Activities
- Item 1206 – Present Activities
- Item 1207 – Delivery Commitments
- Item 1208 – Oil and Gas Properties, Wells, Operations and Acreage

As in the case of reserves, requiring disclosures based on fixed percentages within geographic areas, rather than relying on each company to determine the "meaningful disclosure in the circumstances" has the potential to significantly increase the complexity of data disclosed without any corresponding increase in the value of the information to financial statement users. For example, the geographic dispersion of data for the other disclosure items may be very different than for reserves, resulting in disclosures that are too granular in some areas or too aggregated in others. We recommend that the determination of geographic segmentation for these other disclosures also be left to management's judgment. Management can best decide the appropriate segmentation for each disclosure item, based on its knowledge of the business and assessment of the data distribution for each disclosure category.

Are the proposed 15% and 10% thresholds appropriate? Should either, or both, of these percentages be different? For example, should both be 15%? Should both be 10%? Would 5% or 20% be a more appropriate threshold for either or both?

As noted above, we recommend that the staff delete all such thresholds from the final rule proposal. To the extent the staff feels that the final rule must include some geographic thresholds, we recommend that they be limited to the country level. Mandated disclosure on the basis of sedimentary basin or field has the potential to result in inconsistent or incomparable disclosures due to differing, but well-founded, technical and legal definitions of each of those terms. Moreover, to the extent the additional geographic disclosure is intended to provide financial statement users with additional insight into potential non-technical risks associated with the particular reserves (e.g., political risk), that purpose is fully satisfied by a country by country disclosure.

Note that, in addition to the fact that information on a basin or field basis is unlikely to be effectively comparable or meaningful to an investor (as recognized by the staff's own questions below), the disclosure of such information has the potential to put the disclosing party at a significant competitive disadvantage vis-a-vis its competitors – particularly given the broad range of data to which this disclosure mandate might apply.

Consistent with our comments above, we believe the current principles-based system of geographic disclosure effectively serves the interest of both the disclosing company and the investment community. If additional disclosure on the basis of geography is mandated, we believe it should be limited to a country by country disclosure. With respect to such country by country disclosure, we recommend consideration of a high percentage threshold to ensure that the disclosure is, indeed, meaningful. For this reason, we recommend mandating disclosure only if reserves within a particular country exceed 20% of the registrant's global oil and gas reserves on an oil equivalent basis.

What would be the impact to investors if companies are permitted to omit disclosures based on the individual field or basin due to concerns related to competitive sensitivities? Would investors be harmed if disclosure based on the individual field or basin is omitted due to concerns related to competitive sensitivities? Is there a better way to provide disclosure that a company heavily dependent on a particular field or basin may be subject to risks related to the concentration of its reserves?

We do not believe investors will be harmed by the omission of disclosures based on the individual field or basin. To the contrary, we believe that giving companies the option to omit such disclosure protects shareholders from a potential loss in value of their investment due to the competitive damage that can be caused by such detailed disclosure. Consistent with a principle-based disclosure system, we think management is in the best position to determine the appropriate level of disclosure, balancing both the need for transparent, meaningful disclosure to prospective investors, while also protecting the economic interests of current shareholders. As stated previously, we believe that mandating specific disclosure thresholds is inappropriate and undermines management's ability to strike the appropriate balance between what are sometimes competing objectives.

As noted above, we believe that requiring basin or field level disclosures has the potential to put the disclosing party at a competitive disadvantage, particularly because the disclosure obligation is likely to extend well beyond proved reserves. Moreover, we believe that such competitive disadvantage may occur without any corresponding benefit to investors and other financial statement users – even ignoring potential issues regarding consistency and comparability arising from the definitions of "sedimentary basin" and/or field (both legally and technically) as applied in this context.

Would greater specificity cause competitive harm? Is so, how can the rules mitigate the risk of harm?

Yes, we believe greater specificity, particularly at the field or basin levels, can cause competitive harm. Such disclosures can undermine the negotiating positions of companies in future property sale transactions, unitization agreements or other asset transfers. Also, information about individual fields or basins is sensitive data that is often subject to restrictions by the national governments that have awarded the concession rights.

We believe that the current principles-based approach, requiring geographic disclosure to the extent such disclosure is, in fact, meaningful to investors or other financial statement users, best suits the needs of that community as well as preparers. Rigid bright line disclosure rules, that undermine management's ability to apply judgment, are contrary to this broad principles-based approach and undermine its strength.

In the event that the FASB does not amend SFAS 69, should we require companies to supplement their SFAS 69 disclosure with greater geographic specificity? If the FASB does not amend SFAS 69, should we require that companies reconcile the differences between the reserves estimates shown in the SFAS 69 disclosure with the estimates presented in the proposed tables?

As noted previously, we encourage the staff to exercise leadership to ensure that the final rule proposal and the related financial accounting standards are conformed to establish a single consistent regulatory framework. We believe a dual reporting framework and attendant requirements to reconcile differences would be extremely costly to companies and confusing to financial statement users. We also believe such an outcome would be contrary to other Commission efforts underway to reduce the complexity of the U.S. financial reporting system. We believe that the current rules regarding geographic disclosure are effective in serving the needs of investors and other financial statement users and should remain in place.

iv. Separate disclosure of conventional and continuous accumulations

Should we require separate disclosure of conventional accumulations and continuous accumulations, as proposed?

No, as stated previously, we do not believe that separate definitions of conventional and continuous accumulations are needed. We believe the disclosures should continue to be differentiated by end-product (i.e. oil and natural gas) rather than the type of accumulation. We recommend that the staff eliminate the proposed segmentation by conventional and continuous accumulations. We believe that the proposed disclosure, when coupled with other requirements in the rule proposal, will make the resulting disclosures so complex and granular as to reduce the informational content for financial statement users, while greatly increasing the cost and complexity of record keeping by preparers.

Should we permit combining of columns if the product of the oil and gas producing activity is the same, such as natural gas, regardless of whether the reserves are in conventional or continuous accumulations?

Yes, combining columns based on the end-product (oil or natural gas) will be better than having a separate column for each product based on the type of accumulation. Segmenting the reserves among so many parameters makes the resulting disclosures unwieldy, reduces the informational content for financial statement users and unnecessarily increases the cost and complexity of company record keeping.

For instance, assuming that the FASB does amend SFAS 69 to be in conformance with the final rule, the SFAS 69 proved reserves disclosures will need to follow the same product splits. This will result in several additional pages of SFAS 69 proved reserves disclosures. At least one page of disclosure will be needed for each of the products that a company may have from these various production methods, since each will require three years of data, with the change in each year due to revisions, improved recovery, extensions/discoveries, etc., split by the appropriate geographical segmentation and split between consolidated and equity companies. As a result, it will not be readily apparent what the total liquids and the total natural gas reserves for a company are and where they are reported, which are what most investors and other financial statement users want to know, not how they are produced.

v. Preparation of reserves estimates or reserves audits

Should we require companies to disclose whether the person primarily responsible for preparing reserves estimates or conducting reserves audits meets the specified qualification standards, as proposed? Should we, instead, simply require companies to disclose such a person's qualifications?

Should we require disclosure regarding a person's objectivity when a company prepares its reserves estimates in-house? Should the proposed disclosures regarding objectivity be required only if a company hires a third party to prepare its reserve estimates or conduct a reserves audit, as proposed?

If a company prepares its reserves estimates in-house, should we require disclosure of any procedures that the company has taken to preserve that person's objectivity? Should we require disclosure of whether the internal person meets specified objectivity criteria? For example, should we apply the some of the same criteria that we propose to apply to third party preparers? If so, which ones?

Consistent with the SPE's auditing guidance regarding internal auditors, should we require companies to disclose whether that person (1) is assigned to an internal-audit group which is (a) accountable to senior level management or the board of directors of the company and (b) separate and independent from the operating and investment decision making process of the company and (2) is granted complete and unrestricted freedom to report, to one or more principal executives or the board of directors, any substantive or procedural irregularities of which that person becomes aware?

Should we require disclosure with other specific independence or objectivity standards and, if so, what?

Should we revise any of the proposed provisions regarding a person's objectivity or technical qualifications? Should the proposal require disclosure of other criteria that would have bearing on determining whether the person is objective or qualified?

Should a company be required to present risk factor disclosure if its reserves estimates were not prepared by a person meeting the objectivity and technical qualifications?

Because of the inherent uncertainty regarding estimates of probable and possible reserves, should we require the proposed disclosure only if a company chooses to disclose probable or possible reserves?

Should we require that a third party prepare reserves estimates or conduct a reserves audit if a company chooses to disclose probable or possible reserves estimates?

Should we require the proposed disclosure only if the company is using technologies other than those which are allowed in our current definitions to establish levels of certainty?

We believe that all of the proposed disclosures concerning the qualifications and objectivity of in-house and third party reserves estimators are inappropriate and impractical to implement.

We agree that the competency of reserve estimators is essential to ensuring that reported reserves are assessed and categorized according to generally accepted engineering and geoscience methodologies and that the assessments comply with regulatory requirements. Additionally, the internal control processes for management review and approval of reserves estimates should be robust and transparent.

However, we believe the proposed disclosures are so burdensome as to be impractical. The technical analyses required to arrive at a quality reserves assessment often require input from several disciplines and individuals. As a result, we have hundreds of personnel involved to some degree in the reserves estimation process around the world. Citing the qualifications of each employee will be burdensome and likely of little value or interest to an investor or financial statement user. Even a summary disclosure of qualifications will be daunting to develop, particularly considering the difference in educational systems, licensing and certification requirements and professional bodies from country to country. Lastly, the reserves disclosures are subject to the same internal control and management certification requirements as for the rest of the financial statements under Sarbanes-Oxley. We do not understand why the reserves estimation process should therefore be subject to what essentially amounts to a duplicative disclosure and certification process.

In lieu of detailed disclosures about individual qualifications, we recommend that the staff consider requiring an alternative disclosure describing the internal control systems applicable to the reserves estimation and reporting processes. This could include statements regarding the technical assessment routine, management review and approval processes and the internal audit process, as well as a summary description of the qualifications of typical reserves estimators. We believe this would be a more appropriate topic for discussion, would more broadly address the issues contemplated in the proposed disclosures from a management perspective and thus would be more consistent with the objectives of a principles-based disclosure system. If this is not an acceptable alternative, we recommend that, at a minimum, the staff clarify in the rule proposal that the proposed disclosures be limited to the chief technical person who oversees the company's overall reserves estimation process. In any event, we do not support mandatory licensing for any company personnel involved with reserves estimating.

vi. Contents of third party preparer and reserves audit reports

Should we require a company to file reports from third party reserves preparers and reserves auditors containing the proposed disclosure when the company represents that a third party prepared its reserves estimates or conducted a reserves audit? As an alternative, should we not require that the third party's report be filed, but that the company must provide a description of the third party's report? If so, should we specify that the company's description of the third party's report should contain the information that we propose to require in the third party's report?

Should we specify the disclosures that need to be included in third party reports? If so, is the disclosure that we have proposed for the reserves estimate preparer's and reserves auditor's reports appropriate? Should these reports contain more or less information? If they should include more information, what *other information should they include? If less, what proposed information is not necessary?*

In an audit, should we specify the minimum percentage of reserves that should be examined and determined to be reasonable? If so, what should that percentage be? Should it be 50%, 75%, 90% or some other percentage? If so, why?

If the company engages multiple third parties to conduct reserves audits on different portions of its reserves, should the definition of reserves audit be conditioned on each third party evaluating at least 80% of the reserves covered by its reserves audit, as proposed? Is the scope of a reserves audit defined by geographic areas? If so, should the definition of a reserves audit be based on the third party's evaluation of 80% of the reserves located in the geographic areas covered by the reserves audit?

Would disclosure that a company has hired a third party to audit only a portion of its reserves be confusing to investors? Is there a danger that investors will not be able to ascertain the extent of the reserves audit? Should we require that a company could not disclose that it has conducted a reserves audit unless 80% of all of its reserves have been evaluated by a third party or, if the company hires multiple third parties, by all of the third parties collectively?

Is the proposed definition of "reserves audit" appropriate? Should we revise this proposed definition in any way?

This area is not particularly significant to us since we make minimal use of third party assessments. When an outside assessment is obtained, it is normally because a financial institution has required it as a condition for providing capital to co-venturers. These assessments are prepared according to the requesting institution's guidelines, which could be, and apparently often are, inconsistent with the Commission's reporting requirements. As a result, these assessments normally play no role in supporting our reserves estimates in filed documents with the Commission. If a company elects to utilize third party assessors in preparing or auditing reserves statements, we believe the company has the same responsibility with respect to the third party as in the case of in-house estimators to ensure that the reserves estimates or audits are prepared in accordance with regulations and that the assessors are properly qualified and independent. However, we believe the disclosures contemplated in the rule proposal are excessive and will likely be of little value or interest to an investor or financial statement user. We believe our previous recommendation for an alternative disclosure describing the internal control systems applicable to the reserves estimation and reporting processes is very appropriate for this case. Companies could disclose that they are using third party estimators, to what extent and how they have modified their internal control processes. We believe this would be a more appropriate topic for discussion, would more broadly address the issues contemplated in the proposed disclosures from a management perspective and thus would be more consistent with a principles-based disclosure system.

vii. Solicitation of comments on process reviews

Should we require disclosure of whether a company has conducted a process review? Notwithstanding the relative lack of rigor of a process review compared to a reserves audit, would investors find such information useful?

The proposal does not prohibit disclosure of process review. Is there a danger that the public may be confused by such disclosure? Should we prohibit disclosure of any type of reserves-related activity other than the preparation of the reserves estimates or a reserves audit?

We believe that periodic internal process reviews can be helpful in ensuring the adequacy and effectiveness of a company's reserves estimation process. However, we believe disclosure should be at the option of each company as currently proposed. Consistent with our previous recommendation for an alternative disclosure describing the internal control systems applicable to a company's reserves estimation and reporting processes, we believe this is another aspect that could be appropriately reflected in such a disclosure.

4. Proposed Item 1203 (Proved undeveloped reserves)

Should we adopt the proposed table? Alternatively, should we simply require companies to reclassify their PUDs after five years?

No, we recommend that the proposed table be deleted from the final rule. We also recommend no bright line requirements be introduced for PUD recognition or derecognition. As stated previously, we believe that the use of bright line tests and mandated disclosures should be avoided throughout the rule proposal as these almost always lead to unnecessary complexity and are inconsistent with a principles-based regime.

The aging and tracking of PUDs by their year of recognition and the tracking of related investment dollars would be a complex new reporting requirement that will necessitate costly changes to both accounting and reserves information systems. Given the increasing scale and term of industry development projects, we believe these disclosures will apply to an increasingly significant portion of reported reserves, further compounding the complexity of the proposed disclosures. Lastly, we believe these additional disclosures will be of limited incremental value to financial statement users in assessing a company's success in developing resources given the other multi-year production and proved reserves information already provided.

We also see definitional issues with the proposed disclosures. PUD investments can often span several calendar years as construction and installation of above ground facilities typically precede the final drilling efforts. The guidelines to the table presume that all of the investment dollars will be spent in the year of addition. This will be an infrequent occurrence. Accordingly the table will either need to reflect the multi-year dimension of PUD investments or it will need to consolidate multi-year investment dollars and associate them with the year that the PUDs were transferred to proved developed reserves. Either case will make the disclosure much more complex and difficult to implement and without further explanation will be confusing to investors and other financial statement users. Similarly the proposed disclosure will require companies to make many arbitrary investment cost allocations as some investments may support multiple tranches of PUDs that will be transferred to proved developed reserves over successive years. We also believe the proposed five-year time line for the table is inconsistent as all other reserves disclosures are reported on a three-year time frame.

We oppose reclassification of PUDs after 5 years, as this will unduly penalize companies who have taken on large, complex projects requiring extended development periods. As noted above, given the increasing scale and life of industry development projects, we believe the five-year reclassification restriction will apply to an increasingly significant portion of reported reserves. We understand the Commission's concerns in this area and agree that PUDs should be removed from proved reserves when there is no intent or capability by the company to develop them. However, derecognition based on an arbitrary time frame would be inconsistent with a principles-based disclosure system and could be confusing to investors and other financial statement users. As stated previously, we believe that the recognition of PUDs should continue to be based on management's comprehensive assessment of the geoscience, financial, commercial and operational aspects of each development project versus the standard of reasonable certainty. In the case of PUDs, recognition should particularly be dependent on management's firm commitment to develop the reserves over the project's anticipated time horizon.

Should the table require disclosure of other categories of changes to the status of PUDs, such as acquisitions, removals, and production? Should we add any categories?

No, these other categories will only add to the complexity and cost of the proposed disclosure and will provide no incremental benefits to investors or other financial statement users. The current disclosure requirements for proved reserves require a reconciliation of the changes in balances from the beginning to the end of each reporting period, including change categories for revisions, purchases, sales, improved recovery, extensions and discoveries and production. We believe these disclosures are more than adequate and do not need to be further broken down by PUDs and proved developed reserves.

Some of the abuse related to PUD disclosure may be related to companies' desire to show proved reserves in light of our prohibition on disclosure of probable reserves. Would the proposed rules permitting disclosure of probable reserves reduce the incentive to categorize reserves as PUDs? If so, is the proposed table necessary?

We are not familiar with the referenced abuses in PUD disclosures. Accordingly, we have no basis to determine if the disclosure of probable reserves will reduce such abuse and to what degree.

Should we require disclosure of the reasons for maintaining PUDs that have been classified as PUDs for more than five years, as proposed? If not, why not?

No, we do not think this disclosure should be required. As noted above, we believe this requirement will apply to an increasingly significant portion of reported reserves, further expanding the complexity of the proposed disclosures. Again, we strongly believe that the use of bright line tests and mandated disclosures should be avoided throughout the rule proposal as these almost always lead to unnecessary complexity and are inconsistent with a principles-based regime. We believe this arbitrary five-year requirement could lead investors and other financial statement users to the incorrect conclusion that the disclosing company lacks the commitment or capability to develop such reserves, when it is merely a reflection of the nature of large-scale, complex projects. We also believe that this disclosure could force companies to disclose potentially sensitive competitive data as we believe the circumstances driving a longer than five-year development time frame could differ by field or basin. For example, if development of a major project for a particular field exceeded five years, the detailed disclosures proposed could give competitors insight into a company's marketing plans and sales strategies. Competitors could use this information to direct competing supply into the intended market threatening existing contractual sales arrangements, sales prices realizations and the access to and cost of infrastructure.

Should we require a company to disclose its plans to develop PUDs and to further develop proved oil and gas reserves, as proposed? If not, why not?

Should we require the company to discuss any material changes to PUDs that are disclosed in the table? If not, why not?

In lieu of the proposed table, we recommend an alternative requirement to disclose the quantity of company PUDs, the progress that the company made during the year in converting them to proved developed reserves and material PUD changes that occurred during the year. We suggest this information be disclosed with the proved oil and gas reserve quantities table required by SFAS 69, "Disclosures about Oil and Gas Producing Activities." We believe this approach will be more consistent with a principles-based approach and of more value to financial statement users.

5. Proposed Item 1204 (Oil and gas production)

Should we adopt the proposed table?

The proposed table is acceptable with two exceptions: 1) the requirement to split revenue and costs between conventional accumulations (e.g., oil and gas) and continuous accumulations (e.g., bitumen), and 2) the requirement to split production costs between oil, gas, and any other product. Concerning the first point, as noted above, we believe that disclosures which split reporting between conventional and continuous accumulations provide minimal value to investors. In regards to the second point, oil and gas production is often commingled in well bores and splitting common costs between flow streams can be an arbitrary allocation. If there is a desire to show production costs on a unit of production basis, the measure should be costs per total barrel of oil equivalent, i.e., total production costs divided by total production with gas being converted into an oil equivalent using a standard measure (e.g., six thousand cubic feet of gas = 1 barrel).

Should the disclosure be made based on the proposed definition of "geographic area," or should we continue to follow the definition set forth in SFAS 69?

The disclosure should be made based on the applicable definition of "geographic area." As noted above, we believe the lowest appropriate geographic denominator is the country level. We strongly recommend consistency be maintained with the geographic aggregations being used for the SFAS 69 disclosures.

Should we eliminate the instructions listed above, as proposed? If not, which instructions should we retain? Please explain why those instructions continue to be useful.

We recommend retaining the instructions on the use of marketable gas and the calculation of average production costs to help ensure the disclosure is being prepared on a consistent basis between companies. The marketable gas definition provides clarity on the difference in volume streams for this calculation versus the one used for the proved reserve table (e.g., gas consumed in field operations or flared). The average production cost definition is important information to the investor since this calculation excludes depreciation and depletion costs and all taxes.

6. Proposed Item 1205 (Drilling and other exploratory and development activities)

Should we adopt the proposed table? Should the disclosures be made based on the definition of "geographic area" in proposed Item 1201(d)?

No, we believe the proposed table increases the granularity and complexity of well disclosures, does not provide useful, relevant information to financial statement users and is therefore not cost benefit justified. We believe the table as proposed will confuse investors, particularly in the suspended well area.

Given advances in drilling technology, which have reduced the need for the number of wells to develop a specific field versus past practices, we question whether the drill well tables are presenting an accurate picture to investors of a company's actual development activity over time. Given the need for fewer wells, a tabular, numeric comparison of well counts over time likely presents a misleading indicator of actual field development activity to investors, diminishing any value that it provides. We also believe that disclosure of "any other exploratory or development activities conducted" in the past three years is already covered in the existing Form 10-K disclosure requirements covering the "Review of Principal Ongoing Activities in Key Areas." If the proposed disclosures were made, we believe they should be done on the same "geographic area" used in proposed item 1201(d).

Should we require separate disclosure about the two new proposed categories of wells—extension wells and suspended wells? Does distinguishing these types of wells from exploratory wells and dry wells provide enough clarity regarding the types of exploratory or development activities?

We do not support separate disclosure of the two new proposed categories of wells, namely extension wells and suspended wells. If extension wells were to be reported, additional clarity is needed in the definition to emphasize that these wells are a subset of the exploratory well category. The new requirement to further segregate the exploratory well category between those wells testing for "new sources of oil and gas" versus those wells that are "merely the extension of an existing field" is a distinction that will require much more specific rule-making by the staff before it could be consistently applied in practice. We believe the proposed inclusion of suspended wells in the table is particularly problematic. The definition of a suspended well in this table is a well which has been drilled but not completed. The company may do additional work in the future (e.g., the well is not being abandoned nor called dry or successful). In contrast, a suspended well, as defined in SFAS 19-1, is an exploratory well which finds reserves but those reserves cannot be classified as proved when drilling is completed. SFAS 19-1 requires an extensive set of disclosures on these wells. We believe the proposed table, which uses a different suspended well definition than SFAS 19-1, will be very confusing to investors. It is also unclear how individual wells will migrate to and from this category over time. We believe the table as currently defined will also result in a single well bore being counted twice if it was "suspended"; once in the year the well was drilled and again in the year the well was completed. We question the need for this additional segmentation as we do not believe there are a significant number of wells which have been drilled, but then suspended prior to completion. If a company has such a well, and it is material to its operations, scope already exists in the current MD&A to disclose this activity.

7. Proposed Item 1206 (Present activities)

Should the disclosure of present activities be made based on the definition of "geographic area" in proposed Item 1201(d)?

The disclosure of present activities should be based on the proposed definition of "geographic area," provided the lowest denominator is the country level.
Should we adopt any other changes to the disclosures currently set forth in existing Item 7 of Industry Guide 2 that we propose to codify in Item 1206?

No, we do not believe any other changes are needed. We recommend that the current guidance requiring disclosure of only specific operations that are material to a company's operation be retained.

8. Proposed Item 1207 (Delivery commitments)

Are the proposed revisions appropriate? Do the proposed revisions make any unintended substantive changes to the existing disclosures?

The proposed revisions are acceptable and we do not believe they make any unintended substantive changes to the existing disclosures.

Should we adopt any substantive changes to the disclosures currently set forth in Item 8 of Industry Guide 2 that we propose to codify in Item 1207?

No, we do not believe any substantive changes are needed to the disclosures in Item 8 of Industry Guide 2.

Is this disclosure requirement still necessary? Do oil and gas companies still enter into such delivery commitments? Are they material?

We do not believe this disclosure is still necessary. Most companies that have delivery commitments also have "force majeure" clauses in those contracts which limit a company's liability in the event reservoir performance falls below expectations.

9. Proposed Item 1208 (Oil and gas properties, wells, operations, and acreage)

i. Enhanced description of properties disclosure requirement

Are the proposed disclosure enhancements regarding oil and gas properties appropriate? Would this enhanced disclosure be helpful to investors?

We do not support the proposed disclosure enhancements. We believe the existing broad guidelines in Item 102 of Regulation S-K are appropriate and allow management the flexibility to decide the appropriate level of disclosure based on their knowledge of the business and the materiality of each operation. We believe further expansion of the extensive information already provided under item 102 will be of minimal incremental benefit to investors and will not justify the related costs.

Should the disclosures be made based on the definition of "geographic area" in proposed Item 1201(d)?

If the disclosures are required, they should be based on the definition of "geographic area" as proposed in item 1201(d), provided that the lowest geographic denominator is the country level and that it is consistent with the geographic aggregations used for SFAS 69 disclosures.

Do we need to define any of the terms in the proposed language?

The definitions in the proposed language are adequate.

ii. Wells and acreage

Is the proposed table appropriate? Is there a better way to disclose such information?

We do not believe that disclosure of well and acreage information is particularly meaningful information to investors and other financial statement users, and rather than expanding the current disclosure requirements, we believe they should be left unchanged.

However, if required, the proposed table for wells is appropriate, but splitting out wells associated with other products should not be required. As detailed in earlier responses, disclosures should be based on the end product (i.e. oil or gas) rather than by the nature by which the volumes are extracted.

If required, the proposed acreage table is appropriate. However, added disclosure around areas such as expiring undeveloped acreage, in many instances will adversely impact a company's competitive position and should not be required.

Should the disclosures be made based on the definition of "geographic area" in proposed Item 1201(d)?

The disclosures should be based on the definition of "geographic area" in proposed item 1201(d), provided the lowest geographic denominator is the country level and is consistent with the geographic aggregations used in the SFAS 69 disclosures.

Is it necessary to disclose wells and acreage in conventional accumulations separate from wells and acreage in continuous accumulations, as proposed?

As noted previously, we do not support splitting the wells and acreage disclosures by conventional accumulations and continuous accumulations. We believe this split will be of limited value to financial statement users.

Is this disclosure requirement still necessary? Is disclosure of the number of wells and acreage material? Should we require the disclosures related to wells and acreage only if there is a high concentration of production or reserves attributable to a few wells or limited acreage? If so, should we specify what that concentration would be?

As noted previously, we do not believe that disclosure of wells and acreage data is meaningful information to investors. If required, we are supportive of retaining the present disclosures without adding additional detail such as new well categories or splitting disclosures between conventional and continuous accumulations.

iii. New proposed disclosures regarding extraction techniques and acreage

Should we require more specific disclosure regarding extraction activities that do not involve wells? Should this proposed item remain open-ended to permit description of unanticipated technologies?

We believe that the current level of disclosure already provided in the required discussion of Business Activities and MD&A is sufficient and provides meaningful information to the investor. We do not believe that there should be specific additional requirements for extraction activities not involving wells. We recommend that this disclosure requirement remain open-ended and registrants have flexibility to describe new or enhancements to existing technologies.

Is the proposed disclosure for unproved properties appropriate? Should the proposed disclosure for unproved properties be set forth in proposed Item 1208?

Should we move such disclosure to the reserves table in proposed Item 1202, where reserves are discussed?

We believe that the proposed additional disclosure requirements for unproved properties are excessive and are not appropriate if a registrant chooses not to optionally report reserves related to unproved properties.

10. Proposed Item 1209 (Discussion and analysis for registrants engaged in oil and gas activities)

Proposed Item 1209 is not intended to increase a company's disclosure requirements, but specify disclosures already required generally by MD&A. Is such an item helpful?

Are the proposed topics that an oil and gas company should consider discussing as part of MD&A, whether in the main MD&A section or in conjunction with the relevant table, appropriate? Are there other topics that an oil and gas company should consider discussing?

Should we permit such discussions in conjunction with the relevant table as proposed? Would this aid comparability of the disclosures? Or should we keep MD&A as a self-contained section?

We view this as a new and expanded MD&A disclosure requirement since it specifies a number of detailed disclosure items which are not referenced elsewhere in any of the Commission's guidelines. Many of the requested disclosures are at such a detailed level (for example, discussion of the performance of individual producing wells, including water production and the need to use enhanced recovery techniques) that they will not provide meaningful or relevant information to a financial statement user. Also, some of the new MD&A requirements are complex and costly to implement (for example, the disclosure of anticipated capital expenditures to convert PUDs to proved reserves will be a complex new reporting requirement that will require changes to both accounting and reserves information systems). In addition, several of the disclosures could cause competitive harm to the disclosing company (for example, anticipated exploratory activities, well drilling and production; anticipated capital investment in PUDs; remaining terms of leases and concessions; prices and costs data). We recommend that the staff delete these new disclosures or, alternatively, limit the list of potential disclosures to items that could be material to an investor.

We also note that some of the requested discussion on changes in proved reserves overlaps with requirements found in SFAS 69. We think this is a good example of an area where it will be helpful for the staff to work with the FASB to align the rule proposal with the related accounting standards to minimize the complexity of the resulting regulatory system.

To the extent that some of the proposed additional disclosures are ultimately required, we believe it will be more appropriate for them to be displayed in conjunction with the relevant tables.

IV. Proposed Conforming Changes to Form 20-F

We are not directly affected by the rules applicable to foreign private issuers, however, we appreciate the opportunity to comment on the proposed conforming changes.

We agree with the staff's statement that the rule changes will promote more consistent and comparable disclosures among oil and gas companies. We believe establishing a "level playing field" in this regard benefits investors and other financial statement users as well as companies required to make the disclosures. We also believe that it is consistent with establishing a principles-based disclosure system.

Should we delete Appendix A and refer to Subpart 1200 with respect to Form 20-F, as proposed? Why? Should we expand the requirements of Form 20-F to require more disclosure than currently required by Appendix A, as proposed? Conversely, should we only update Appendix A to reflect the proposed new definitions and formats for disclosing reserves and production?

As noted above, we believe that the proposed expansion of the requirements of Form 20-F to require more disclosure than currently required by Appendix A is consistent with and will promote the Commission's overall goal of enhancing disclosure consistency and comparability. We likewise find it an appropriate modification that is consistent with establishing a principles-based disclosure system. While updating Appendix A solely to reflect the proposed new definitions and disclosure format would seem to be the minimum change that could be implemented, we believe adopting the more expansive approach proposed helps to "level the playing field" for all companies in the industry.

Would the proposed reference to Subpart 1200 in Form 20-F significantly change the information currently disclosed by foreign private issuers? If so how? Would such a change be appropriate?

We believe this will likely increase the amount of information disclosed by foreign private issuers but we believe this is appropriate for the reasons stated above.

Is the proposed exception for foreign laws that prohibit disclosure about reserves and agreements appropriate? Do such laws affect domestic companies as well? Should Subpart 1200 have a general instruction with respect to such foreign laws?

Given the global nature of the industry, both domestic (U.S.) and foreign-based companies have the potential to have operations in jurisdictions that preclude disclosure of reserves and agreements. Consequently, a single approach to the issue applicable to all companies would be appropriate and consistent with the stated goals of improving the consistency and comparability of company disclosures. To avoid ambiguity, we suggest that guidance on foreign laws be incorporated into a general instruction for Subpart 1200. We believe this guidance should indicate that if required information is not disclosed because a foreign government *affirmatively* restricts the disclosure of estimated reserves for properties under its governmental authority, or amounts under long-term supply, purchase, or similar agreements subject to its governmental authority, the registrant should disclose the country, cite the law or regulation which restricts such disclosure, and indicate that the reported reserves estimates do not include amounts for the named country.

Are the proposed revisions to Instructions to Item 4.D appropriate with respect to foreign private issuers that have extractive activities other than oil and gas producing activities?

Similar to our position on Item 1208 (iii), we believe that the current level of disclosure provided in the required discussion of Business Activities and MD&A is sufficient and provides meaningful information to the investor. We do not believe that there should be specific additional requirements for extraction activities not involving wells. We recommend that this disclosure requirement remain open-ended and that registrants have flexibility to describe new technologies or enhancements to existing technologies.

V. Impact of Proposed Amendments on Accounting Literature

B. Change in Accounting Principle or Estimate

Are the proposed changes more properly characterized as a change in accounting principle or a change in estimate under SFAS 154?

We believe the proposed changes are properly characterized as a change in estimate under SFAS 154 and should be accounted for on a prospective basis.

Would it be appropriate to consider the changes as a change in accounting principle, but specify that no retroactive revision of past years would be required?

We do not believe it would be appropriate to consider the changes as a change in accounting principle even if there was no retroactive revision of prior years.

If we required retroactive revision of past years, would companies have the historical engineering and scientific data to make such revisions? If not, are there alternatives to retroactive revision that we should consider?

Retroactive revisions of prior year's reserves and financial data would require a very significant effort with minimal benefit to an investor. We believe most companies will have the technical data needed for a restatement of prior years, but could not justify the significant effort required for such a project since the changes to both the financial statements and reserve tables would most likely be immaterial.

C. Differing Capitalization Thresholds Between Mining Activities and Oil and Gas Producing Activities

How should we address these inconsistencies between oil and gas accounting rules and mining accounting rules?

Should we permit companies that extract, through mining methods, materials from which oil and gas can be produced to continue to capitalize costs under mining rules, or should we require them to capitalize costs based on oil and gas rules? Are there circumstances involved with mining operations, different from oil and gas operations, that justify capitalization of costs of proved plus probable reserves, as opposed to only costs of proved reserves?

We believe that the accounting and disclosures for operations that extract oil and gas through mining methods should be conformed to the SFAS 19 accounting methodology for oil and gas activities. We do not believe this will create material changes in accounting results on transition or thereafter. We believe that getting these resources on a consistent accounting and disclosure methodology with conventional oil and gas activities will improve the consistency and comparability of financial reporting. Similar to previous comments, we believe that all accounting and disclosures should focus and be aligned on the basis of the product that is produced rather than the extraction method utilized to produce the product.

D. Price Used to Determine Proved Reserves for Purposes of Capitalizing Costs

Would the effect of such changes be material or have a material effect on historical amortization levels?

Would the effect of such changes be material or have a material effect on comparability? Please provide any empirical evidence to support your conclusion.

Would it be appropriate to continue to require the use of the year-end price for purposes of determining reserves for purposes of amortization expense while using a different price for purposes of disclosing reserves estimates in Commission filings? This would result in a different value associated with the use of the term "proved reserves" for purposes of disclosure, as opposed to the use *of that term for purposes of accounting. Would this be confusing? Should we use a different term? Should we otherwise clarify the two different meanings of that term in different contexts?*

We strongly recommend that the proved reserve quantities included in disclosures and used for SFAS 19 accounting purposes be based on the same 12-month average prices. The use of two pricing bases will sever the link between the required disclosures and the related financial accounting which is not consistent with an effective and transparent reporting model. The maintenance of such a "two-price" system will be unduly costly and burdensome for registrants, and it will likely confuse financial statement users such that additional disclosures might be required to explain the differences.

In view of the typical relationship between the amount of proved reserves and the attendant volume of production during any one accounting period, we believe it is unlikely that any changes to reserve quantities used for depreciation purposes to reflect year-average prices will have a significant impact on a company's reported amortization expense. To the contrary, the use of average prices will reduce the magnitude of changes that may otherwise be caused by large fluctuations in year-end prices. In any event, we do not think that depreciation expense based on single-day, year-end prices yields a conceptually better accounting result than one based on average prices.

VI. Impact of the Proposed Codification of Industry Guide 2 on Other Industry Guides

Is it appropriate to codify Industry Guide 2 separately from the other industry guides? Should we merely amend Industry Guide 2 and codify it with all of the other industry guides when they have been updated?

We support the proposed codification of Industry Guide 2 as part of the current rule making exercise.

Would the codification of Industry Guide 2 overrule or otherwise affect any of the disclosures required in the other Industry Guides?

We are not affected by the other Industry Guides, but we do not believe the proposed codification will unduly affect them.

VII. Solicitation of Comment Regarding the Application of Interactive Data Format to Oil and Gas Disclosures

Should we adopt rules that require oil and gas disclosures to be provided in interactive data format? Instead of requiring such formatting, should we only permit the filing of oil and gas disclosures in interactive data format? What are the principal factors that we should consider in making these decisions?

We believe that the oil and gas disclosures ultimately should be provided in the XBRL interactive data format, consistent with the Commission's current proposal for the rest of the financial statements. However, we do not believe that XBRL reporting should be mandated for the first year of implementation (i.e. for the 2009 Form 10-K). We expect that most industry companies will be challenged in the base case with completing implementation of the new rule proposal, without also having to deal with an XBRL reporting requirement. We recommend that the Commission consider a phased-in implementation, where no XBRL reporting will be required in the first year of implementation (2009 Form 10-K), block tagging in the second year (2010 Form 10-K) and full tagging of all elements in the third year (2011 Form 10-K). We believe this phased-in implementation will be consistent with the Commission's current proposed XBRL implementation approach and schedule for the rest of the financial statements. It will also provide companies the opportunity to develop some experience with the new disclosure requirements prior to implementing them in XBRL.

If we require oil and gas disclosures to be filed in interactive data format, should we provide for a voluntary phase-in period to create a well-developed standard list of electronic tags? Without a requirement, would the development of products for using interactive data meet the needs of investors, analysts, and others who seek to use interactive data? Would a large percentage of oil and gas companies provide interactive data voluntarily and follow the same standard, if not required to do so?

Consistent with the above response, we believe that XBRL reporting of the new disclosures should not be required any earlier than for the 2010 Form 10-K. We have no basis to estimate what percentage of oil and gas companies will or will not provide data interactively if not required to do so.

Would investors, analysts, and others find presentation of oil and gas disclosures helpful if presented in interactive data format? In what ways would such users of the information find such a format beneficial?

It is currently unclear to us whether investors, the financial analyst community and other financial statement users will find XBRL reporting beneficial, or whether they will even attempt to use it.

As we note above, there is not currently a well-developed standard list of electronic tags for the oil and gas disclosures. Are there any obstacles to creating a useful standard list of electronic tags for the oil and gas disclosures? Is the type of data presented in the proposed table conducive to interactive data format? Would it be particularly difficult to create standard electronic tags for any of the proposed data? Would there be any obstacles to providing comparable data in interactive format?

As we are in the initial phase of implementing the XBRL standard and its functionalities, we do not yet have the needed perspective and experience to effectively answer these questions. However, we anticipate that it will take some time to get the electronic tags perfected for industry use, particularly considering the extensive nature of the required disclosures currently included in the rule proposal.

Would it be useful for the data in the proposed tables to interact with other data in Commission filings? If so, which data?

As we are in the initial phase of implementing the XBRL standard and its functionalities, we do not yet have the needed perspective and experience to effectively answer these questions.

If we adopt rules requiring oil and gas disclosures in interactive data format, should we require the use of the eXtensible Business Reporting Language (XBRL) standard? Are any other standards becoming more widely used or otherwise superior to XBRL? What would the advantages of any such other standards be over XBRL?

To the extent that an interactive data format is required, we believe the XBRL standard should be used since this will be the method used for the rest of the financial statements. We do not believe that it will be efficient or practical for preparers or financial statement users to deal with multiple standards.

VIII. Proposed Implementation Date

Should we provide a delayed compliance date, as proposed above? If so, is the proposed date appropriate? Should we provide more or less time for companies to familiarize themselves with the proposed amendments?

Yes, we believe the proposed implementation date is appropriate. The rule proposal in its current form will require a substantial implementation effort by ExxonMobil that will span the better part of a calendar year. If the issuance of the final rule proposal should be delayed into 2009, we believe the Commission will need to consider a delay of the effective date.

If we provide a delayed compliance date, should we permit early adoption by companies?

No, we do not believe early adoption should be allowed. We believe that the implementation date should be kept consistent for all companies to maintain a level playing field and to avoid the potential for investor confusion that may result from the use of differing reporting methodologies during the transition period.

X. Paperwork Reduction Act

We request comment in order to evaluate the accuracy of our estimate of the burden of the collections of information. Any member of the public may direct to us any comments concerning the accuracy of these burden estimates. Persons who desire to submit comments on the collection of information requirements should direct their comments to the OMB, Attention: Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Washington DC 20503, and should send a copy of the comments to Secretary, Securities and Exchange Commission, 100 F Street NE, Washington, DC 20549-1090, with reference to File No. S7-15-08. Requests for materials submitted to the OMB by us with regard to this collection of information should be in writing, refer to File No. S7-15-08, and be submitted to the Securities and Exchange Commission, Records Management Branch, 100 F Street NE, Washington, DC 20549-1110. Because OMB is required to make a decision concerning the collections of information between 30 and 60 days after publication, your comments are best assured of having their full effect if OMB receives them within 30 days of publication.

XI. Cost-Benefit Analysis

We request comment on all aspects of the Cost-Benefit Analysis, including identification of any additional costs or benefits of, or suggested alternatives to, the proposed amendments. We also request that those submitting comments provide, to the extent possible, empirical data and other factual support for their views.

XII. Consideration of Burden on Competition and Promotion of Efficiency, Competition, and Capital Formation

We request comment on whether the proposals, if adopted, would promote efficiency, competition, and capital formation or have an impact or burden on competition. Commenters are requested to provide empirical data and other factual support for their views, if possible.

We offer the following comments in response to the questions in Sections X, XI and XII above.

We are concerned about the extensive new disclosure requirements included in the proposal, most of which were not discussed in the Concept Release. Cumulatively, the new disclosures will necessitate a significant implementation and training effort. For example, many of the proposed disclosures require a degree of granularity not currently present in our reporting and consolidation processes. This will necessitate costly changes to these systems. We believe data disclosures that go beyond what companies use to manage the business on a day to day basis are inherently excessive. The cost-benefit analysis section of the proposal estimates that the new rules will require an incremental effort of 35 hours per registrant. We believe this is significantly understated and that for ExxonMobil the incremental effort could be as high as 15,000 to 20,000 hours. More importantly, we believe some of the proposed disclosures are of little value to financial statement users, do not justify the high implementation costs and can cause competitive damage to the disclosing company in some instances. These disclosures will likely make the U.S. financial markets and U.S. oil and gas companies less competitive internationally and are inconsistent with recent Commission efforts to reduce the complexity of the U.S. reporting system.

Other Comments

Need to Clarify Approach to the Reporting of Equity Company Reserves

The rule proposal is silent on the treatment of equity company reserves and other related information. It appears no differentiation is made between consolidated subsidiaries and equity companies and that only the combined total is to be reported for each disclosure item. We strongly support this combined reporting approach and recommend that the final rules make this explicit. We believe that separate disclosure of consolidated subsidiaries and equity companies, as required in the existing guidelines, has been confusing to financial statement users. We believe an approach that fully integrates equity company data into each disclosure will improve the clarity and the quality of disclosures, particularly since companies view the economic value and importance of equity company reserves and related activities to be equal to those of consolidated subsidiaries. We note this may require an amendment to the examples in SFAS 69. The examples in SFAS 69 do not expressly prohibit the addition of reserves quantities for consolidated companies and equity affiliates, but the staff in comment letters has interpreted the examples to prohibit such arithmetic addition. Alternatively, the staff could withdraw their previous interpretations to allow the full integration of equity company data as we have proposed.