September 8, 2008

Securities and Exchange Commission
100 F Street, NE
Washington, DC 20549-1090
Attention: Florence Harmon, Acting Secretary

PROPOSED RULES ON MODERNIZATION OF THE OIL AND GAS REPORTING REQUIREMENTS
File Number S7-15-08

Dear Ms. Harmon:

Devon Energy Corporation ("Devon") appreciates the chance to comment on the important issue of modernization of oil and gas reporting requirements. Our responses to the Security and Exchange Commission's request for comments are attached. Additionally, Devon provides this synopsis of our response for your convenience.

Devon supports the overall tenor of the proposed rules, which establish a rational, principles-based reserves reporting system. We believe that reserves are an important component of producing companies' financial reports, and the changes envisioned by the Commission are far-reaching and, in general, welcomed. At Devon, we are encouraged by the significant advancements proposed by the Commission in the following areas.

- Elimination of "one-day" pricing for the calculation of reported reserves volumes.
- Establishment of a "principles based" reporting system consistent with the SPE/WPC/AAPG/SPEE Petroleum Resource Management System.
- Inclusion of bitumen, shale, and other non-conventional oil and gas activities.
- Recognition of additional reliable technology for determination of proved reserves.
- Extension of the "reasonable certainty" standard to all proved reserves estimates.
- No requirement for third-party reviews and estimates.

The following are the primary areas where Devon believes the alteration of the proposed rules will result in additional improvement.

- Price – A single price should be used for accounting purposes and for disclosure outside of the financial statements. Utilization of different prices for accounting purposes and disclosures will likely result in confusion for investors. The 12-month trailing average price used for accounting purposes and for disclosures outside of the financial statements should include a lag period between the final month included in the average and the end of the period. An optimal lag period would be 3 months, and should be no less than 1 month.

- Report Reserves by Product – Reporting of oil and gas reserves should be made on the basis of the produced product as versus the type of accumulation. The proposed reporting of reserves by continuous versus conventional accumulation type should be eliminated. Reporting of oil and gas reserves by accumulation type could lead to investor confusion as different companies may report reserves from the same accumulation in different tables. Reporting of reserves by product type would eliminate this confusion.

- Reporting Granularity – The granularity of reporting should be maintained at its current level as described in SFAS 69 (country or region) rather than at "geographic area" levels as discussed in the proposed rules. Requiring granularity at the geographic area as defined in the proposed rules could be an onerous reporting burden for filers, and an unintended effect of damage to a competitive position could also result from such granular disclosures.

- Retroactive Reporting – Requiring reporting companies to retroactively construct new tables requiring data from up to 5 years prior to the initial reporting year is an onerous requirement. The information required to populate the tables for 5 years prior to initial implementation of the new rules has historically not (in many cases) been gathered. A revision of the proposal specifying that the tables would be "phased-in" over five years would be preferable. Requiring granularity at the geographic area as defined in the proposed rules could be an onerous reporting burden for filers, and an unintended effect of damage to a competitive position could also result from such granular disclosures.

- Probable and Possible Reserves Reporting – Consistent with our responses to SEC SR 33870, Devon believes that investors are best served by the reporting of proved reserves only. The inclusion of probable and possible reserves, for which no established enforceable standards exist, could lead to increased litigation and misunderstanding by investors of potential recovery from projects in a company's portfolio of properties.

Devon submits these comments and supports the SEC in its quest for a modern, robust reserves reporting system that will inform investors and all stakeholders in the oil and gas exploration and producing business.

Sincerely,

/s/ K. Earl Reynolds
K. Earl Reynolds
Vice President
Strategic Planning

PROPOSED RESPONSES TO SEC PROPOSED RULES QUESTIONS

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

Questions

B. Year-End Pricing

1. 12-month Average Price

1. 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?

   Answer: Yes, the economic producibility of a company's oil and gas reserves should be based on a 12-month historical average price. If prices are averaged over a period of one year, the effect of price variations due to seasonal volatility is minimized. Utilizing average prices over shorter periods of time may disproportionately reflect seasonal volatility due to weather and other factors. Averaging prices over longer periods may obscure long-term price trends.

2. 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?

   Answer: No, historical prices averaged over a one-year period are the best method for reserves reported in financial filings. The actual prices and differentials are data easily accessible to all producers and are therefore available to substantiate requests for data.

3. 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?

   Answer: If prices for the actual fiscal year are used, utilizing the prices on the first day of the month would be preferred over prices on the last day of the month, as first of the month prices apply to the month ahead. However, utilizing average price information over a twelve-month period ending on September 30 of the current year would be preferable. This method allows ample time to prepare reserves estimates with minimum errors, and that period should be very comparable to the current year estimate of average price.

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

   Answer: Only the base case of historical pricing should be required. Disclosure of pricing sensitivities should be at the discretion of the reporter.

5. 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?

   Answer: A supplemental price sensitivity disclosure would not be necessary as fluctuations in year-end prices would continue to be reflected in financial accounting calculations within the quarterly reports filed by companies.

2. Trailing year-end

1. 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?

   Answer: The annual average price should be based on a trailing average, preferably from October 1 of the previous year to September 30 of the reporting year for those filers with a fiscal year ending on December 31 (with a similar time frame for filers with different fiscal calendars). This scheme would account for seasonal variances for both oil and gas and yet allow sufficient time to prepare accurate, high quality reserves reports. The use of trailing year-end prices as described should aid investors in assessing performance.

2. 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?

   Answer: A lag of three months as proposed above is preferable to aid in the accurate preparation of reserves reports.

3. **Prices used for accounting purposes**

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

   Answer: The Commission should require the same prices for accounting purposes as for disclosure outside of the financial statements. To require a one-day price for ceiling tests will introduce the same volatility into the ceiling tests that will be alleviated in the reserves calculation by using the average annual price (either fiscal year-end or trailing average). In fact, we believe that the use of different pricing scenarios for accounting and disclosure purposes will likely cause unnecessary confusion to investors.

2. 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?

Answer: The Commission should treat both full cost and successful efforts companies similarly and require the same price model for both. As noted previously, we believe that average prices should be used to both determine the quantities of reserves disclosed and for accounting purposes. Accordingly, reserves for companies using either the successful efforts method or full cost method of accounting would be consistently calculated and disclosed.

3. 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?

   Answer: We believe the limitation on capitalized costs (the "ceiling test") for companies following the full cost method should be calculated using the same average price used to calculate the volumes of reserves quantities disclosed outside the financial statements. If the ceiling test were to be calculated using an average price, we believe that an impairment resulting from the use of an average price should be required to be recorded regardless of whether the period-end price was higher than the average price.

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

   Answer: As reflected in the above responses, the SFAS 69 disclosures should be prepared on the same prices as the disclosures required by the proposed Section 1200.

5. 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?

   Answer: The fact that additional disclosures would be necessary to explain that two different quantity measurements have been used indicates to us that it is preferable to use the same average price for both disclosure and accounting measurements. The use of average prices for both measurements will eliminate the potential for confusion to investors.

6. 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?

   Answer: The primary concerns with utilizing different price information for different purposes are the unnecessary volatility in reserves and values and potential for confusion to investors. It is not consistent to use different prices to calculate reserves disclosed for general disclosure purposes from those used to calculate reserves used for accounting purposes, including ceiling tests, particularly where both types of disclosures are included in the same document. Imposition of different prices resulting in different reserves and values would be an unnecessary burden on companies, particularly in light of advanced financial reporting deadlines under the Sarbanes-Oxley regime.

7. 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?

   Answer: The proposed change to definitions of proved reserves and proved developed reserves will likely have some impact on current depreciation amounts and net income. In some cases, proved reserves will increase and reduce depreciation for some companies. It is not possible to quantify the impact at this time.

8. 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?

   Answer: It is not possible to quantify the potential impact since it would be influenced by actual average prices and period-end prices in the future. We believe that whatever the impact, it should not override the consistent use of average prices to determine reserves quantities for both disclosure and accounting purposes.

C. Extraction of Bitumen and Other Non-Traditional Resources

1. 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?

   Answer: The Commission should consider all unconventional resources that result in the production of oil and gas (including synthetic crude oil, natural gas liquids, etc.) as oil and gas producing activities. This includes gas-to-liquids projects, such as the project in the North Gas field in Qatar. These projects result in a petroleum product that can be sold and is fungible.

2. 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.

   Answer: The extraction of coal-bed methane through wellbores should continue to be considered an oil and gas activity.

3. 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?

Answer: See the answers to the questions above.

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

   Answer: It is not possible for us to estimate the impact on the financial statements of individual companies.

D. Reasonable Certainty and Proved Oil and Gas Reserves

1. 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?

   Answer: The proposed definition of reasonable certainty (with the clarifications presented in the SEC proposal) is clear, but leads to a bias towards conservatism. "Much more likely to be achieved than not" implies an estimate that is deliberately conservative and is not supported by the best estimates of the data. Judgment is a key element of reserves estimates (not only deterministic estimates but also probabilistic estimates), and a deliberately low estimate tends to undervalue companies and mislead investors. Modifying the statement to be "much more likely to increase than to decrease" (consistent with current SEC staff guidance) would be more appropriate than the proposal.

2. 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?

   Answer: The proposed 90% threshold for proved reserves when using probabilistic methods is appropriate, but this confidence level is not equivalent to reasonable certainty as applied in a deterministic estimate. Deterministic estimates, when not performed in conjunction with probabilistic estimates, are not accompanied by confidence levels. In PRMS, the equating of reasonable certainty and 90% probability was avoided.

1. New Technology

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

   Answer: The proposed definition of "reliable technology" is appropriate.

2. 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?

   Answer: The open-ended nature of the definition of "reliable technology" is appropriate. One risk associated with adoption of the definition would be inconsistent interpretation among filing companies. Although the Commission did not recommend the establishment of a "Reserves Accounting Standards Board (RASB)" in its proposed rules, such a group could materially aid the Commission staff in questions of this nature, and we recommend the establishment of such a group. Limited manpower at the Commission will probably continue to be the norm, and RASB could be an aid to the staff. RASB could be funded by industry, both with seconded personnel and with administrative support and funds.

3. 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?

   Answer: No, the proposed disclosure of technology used to establish the appropriate level of certainty is not appropriate. In many instances, several different technologies are simultaneously utilized to establish the appropriate level of certainty. Furthermore, disclosure of technology could lead to competitive disadvantages by requiring a company to divulge proprietary technology. In cases where competitive disadvantages are a concern, companies should (upon request by the SEC) confidentially disclose to the SEC what technology is being utilized to establish the appropriate level of certainty.

2. Probabilistic Methods

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

   Answer: A proposed definition for deterministic estimate could read: "…a single best estimate that is based on using a single "most appropriate" value for each variable in the estimation of reserves, such as the company's determination of the oil or gas in place in a reservoir, multiplied by the fraction of that oil or gas that can be recovered." (Underlined words added.) The probabilistic definition is appropriate.

2. 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?

   Answer: No, for the deterministic case, the requirement that an estimated EUR be "much more likely to increase than to either decrease or remain constant" is not appropriate. The definition of reasonable certainty as stated in PRMS is the best definition to use: "If deterministic methods for estimating recoverable resource quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered." Modifying the statement to be "much more likely to increase than to decrease" (consistent with current SEC staff guidance) would be more appropriate than the proposal. The proposal will lead to a more conservative estimate than the SEC currently requires. As stated before, reasonable certainty and 90% probability are not equated. The definition for probabilistic proved reserves as 90% probability of being achieved or exceeded is appropriate and is consistent with PRMS.

3. 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?

   Answer: Companies should have the choice of reserves estimation methods.

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

   Answer: No, companies should not be required to disclose the methodologies utilized.

3. **Other revisions related to proved oil and gas reserves**

1. 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?

   Answer: The Commission should allow the use of technologies that have been proven to be reliable (see above) to establish reservoir fluid contacts.

2. 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?

   Answer: The requirements already established are sufficient to attribute proved reserves to a project. The definition of reserves in the proposed rules includes the level of certainty in financing as well as other factors, and this definition allows the company to book proved reserves under the reasonable certainty of financing. Other factors that bear on the attribution of proved reserves are covered in the proposed definitions.

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

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

   Answer: The Commission should allow only proved reserves to be disclosed. Unproved reserves are uncertain, and although there are established methodologies for estimation of unproved reserves, there are no accepted standards that govern these estimates. The SPE "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" (SPE, February 2007) states explicitly in the footnote on page 1 that the standards "are not intended to bind members of… SPE… or anyone else, and the Society imposes no sanctions for the nonuse of these standards." If reporting of unproved reserves is allowed, an explicit declaration of whether the volumes are risked or unrisked (i.e., that appropriate chance factors of recovery have or have not been applied) should be required. The factors applied as the chances of recovery should also be disclosed. Without these required disclosures, investors are likely to be confused and possibly misled as to the actual expected recovery of unproved reserves. However, the SEC should clarify that whether or not probable and possible reserves are reported does not preclude the current practice of discussing these reserves and resources in non-filed documents.

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

   Answer: No, the commission should not require disclosure of probable or possible reserves.

3. 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?

   Answer: If the Commission adopts rules that permit the disclosure of unproved reserves, the definitions proposed should be adopted. They are consistent with PRMS.

4. 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?

   Answer: If the Commission adopts rules that permit the disclosure of unproved reserves, the probability thresholds proposed should be adopted. They are consistent with PRMS.

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

1. 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?

   Answer: The Commission should adopt the definition of proved developed oil and gas reserves as proposed.

G. Definition of "Proved Undeveloped Reserves"

1. Proposed replacement of certainty threshold

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

   Answer: The proposed revisions are appropriate, as they establish one standard for all proved reserves. The requirement to demonstrate commitment to drill within a reasonable time frame is a significant step to ensure that the potential for abuse is minimized. This will require demonstration and documentation of the proper work to make sure that the locations meet all qualifications for attribution of proved reserves.

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

   Answer: Yes, the single standard of reasonable certainty should be applicable to all proved reserves estimates.

3. 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?

   Answer: Unless special circumstances exist, it is appropriate that all proved undrilled reserves locations must be drilled within the five-year time frame. The special circumstances which would prevent the drilling within that time frame should be clearly documented. This is consistent with PRMS.

4. 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?

   Answer: See the answer to question 3 above. The proposed definition should specify that the exceptions to the five-year window are limited and include such conditions as long-lead-time projects (frontier or deep water areas) and limited access to drilling rigs. In all cases, any location assigned proved undeveloped reserves should be on a drilling or development schedule to which the company is committed.

2. Proposed definitions for continuous and conventional accumulations

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

   Answer: The definitions of conventional and continuous accumulations are appropriate and are consistent with PRMS. Separate disclosure of these accumulations will likely not be helpful to investors and should not be required.

2. 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?

   Answer: The definition is appropriate. The proposed definition does include examples of such accumulations.

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

   Answer: The definition is appropriate and is consistent with PRMS.

3. Proposed treatment of improved recovery projects

1. 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?

   Answer: The definition of proved undeveloped reserves should be expanded to include improved recovery projects that are based on other evidence using reliable technology that establishes reasonable certainty. The advances in technology that have occurred have improved our understanding of reservoir mechanics and do establish reasonable certainty for proved undeveloped reserves. The reliable technology standard must be met.

H. Proposed Definition of Reserves

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

   Answer: The definition of reserves is appropriate and is consistent with PRMS. This definition further extends the PRMS definition to include elements of ownership and existence of markets.

I. Other Proposed Definitions and Reorganization of Definitions

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

Answer: In the main, the definitions are appropriate. One of the definitions needs some modification as follows:

> Analogous formation in the immediate area has, in the past, been taken to mean not only intensive properties (e.g., porosity, permeability, saturations) but also extensive properties (e.g., thickness, area, etc.). If the intensive properties of a formation are as favorable or more favorable as the analogous reservoir, and if the economic producibility is thereby established with a sufficient amount of recoverable hydrocarbons to meet the criteria for economic development, then the analog should be acceptable. In this case, the instructions to paragraph (a)(2) for analogous reservoirs in the immediate area could read:
>
> > "Intensive reservoir properties (e.g., porosity, permeability, fluid saturations, etc.) must be no more favorable in the analog than in the formation of interest. Extensive properties, such as area and thickness, should be such that the development project is economic and meets all the criteria for reserves. When the intensive geological and fluid properties in the formation of interest change significantly and do not meet the test of as favorable as, or more favorable than, the proposed analogous formation, the proposed analog formation can no longer be said to be an analogous formation in the immediate area of the formation of interest."

2. 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?

Answer: The definitions are adequate to address financial filings.

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

Answer: The definitions should be alphabetized, as that makes the terms more easily accessible.

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

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

1. 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?

Answer: The proposed amendment to Instruction 3 is appropriate. The term "extractive activities other than oil and gas activities" is appropriate. Mining activities may cover all other activities, but the proposed term ensures that all future activities are included in the regulation.

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

   Answer: Instruction 6 in Item 102 of the regulation refers to oil and gas operations and Regulation S-X. This instruction should be eliminated.

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

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

1. 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?

   Answer: The instructions are clear, but the granularity is too fine in the tables. Although the existence of one or more fields with a significant percentage of a company's reserves may increase that company's chance of significant revisions, that information is generally proprietary and can lead to a potential loss of competitive advantage. Current reporting in the 10-K requires country and region breakouts, and these are adequate to inform investors of the resources available to a company.

2. 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?

   Answer: Yes, a specified format should be used by all companies. This will make reporting consistent and easy for all investors to read and understand.

3. 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?

   Answer: Conventional and continuous accumulations should not be reported separately. The reporting of reserves estimates should be in one table for the total entity reserves and one table for each included country or region. An appropriate alternative to separate tables for conventional and continuous accumulations is to report by product, similar to that done in Canadian reports under NI 51-101.

3. Proposed Item 1202 (Disclosure of reserves)

i. Oil and gas reserves tables

1. 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 or possible reserves?

Answer: See the answer to Question E(1) above. Only proved reserves should be required disclosures. Unproved reserves (probable and possible reserves) should not be allowed in financial reports. There exist no firm standards for evaluation of probable and possible reserves, and the inclusion of such reserves could lead to inaccurate conclusions by investors. The increased disclosures could be misinterpreted by many users of financial reports.

2. 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?

   Answer: No, the disclosure requirements would not provide sufficient information to develop an understanding of how companies classify reserves. A listing of technologies and assumptions would likely be too voluminous to be of use to investors.

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

   Answer: As defined, probable and possible reserves volumes are "un-risked" volumes. If the Commission allows reporting of unproved reserves in financial filings, risks associated with the likelihood of their recovery should be discussed.

4. 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?

   Answer: For financial disclosures, separate and different reserves categories should not be aggregated.

5. 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?

   Answer: No. Some companies already disclose potential resources in other venues, such as press releases and webcasts. The Commission should monitor (as it currently does) such information to ensure that such resources are not misrepresented as proved reserves in any such information.

6. 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?

   Answer: The proposed aggregation method is acceptable. All reserves above the field or project level should be summed arithmetically, as is recommended in PRMS. Probabilistic aggregation above that level should not be allowed in financial reports.

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

   Answer: Please see the answer to Question E(3) above.

8. 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?

   Answer: The exception regarding the disclosure of resources in the context of an acquisition, merger, or consolidation should remain in the instructions to fully inform shareholders.

ii. Optional reserves sensitivity analysis table

1. 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?

   Answer: A supplemental price sensitivity disclosure should not be required as fluctuations in year-end prices would continue to be reflected in financial accounting calculations within the quarterly reports filed by companies.

2. 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?

   Answer: A supplemental price sensitivity disclosure should not be required as fluctuations in year-end prices would continue to be reflected in financial accounting calculations within the quarterly reports filed by companies.

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

   Answer: See the answer to Question (1) above.

4. 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 12month 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?

   Answer: We strongly encourage the FASB to change its SFAS 69 disclosures to be consistent with the proposed Item 1202 disclosures. If for some reason the FASB elects to not revise its disclosures, we believe disclosure of the fact that the SFAS 69 disclosures are based on year-end prices and the Item 1202 disclosures are based on a 12-month average would be sufficient. We do not believe that detailed reconciliation tables would be necessary under these circumstances.

iii. Geographic specificity with respect to reserves disclosures

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

   Answer: The new requirement to disclose reserves by "geographic area" should not be adopted. The guidance should specify country or region, as is currently required in reserves disclosures. Attempting to add too much granularity to reserves disclosures imposes an onerous burden on reporters, and, in addition, the disclosure of reserves to a field level can be inimical to competitive advantage for any company required to disclose to that level.

2. 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?

   Answer: See the answer to Question (1) above. If the geographic area or field level reporting is required, an appropriate level would be 25% for a geographic area and 20% for a field. The area or field needs to be overwhelmingly material to a company's reserves base for this requirement to be imposed.

3. 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?

   Answer: Requiring companies to disclose reserves by "country or region", as is currently required, would have no impact on investors and would continue to provide relief of concerns related to competitive sensitivities.

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

   Answer: Please see the answer to Questions (1) and (3) above.

5. 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?

   Answer: The greater geographic specificity should not be adopted, thereby alleviating this possible requirement.

iv. Separate disclosure of conventional and continuous accumulations

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

   Answer: No, the Commission should require the reporting of oil and gas reserves by product rather than by type of accumulation.

2. 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?

   Answer: Yes, reserves should be reported by product rather than by accumulation type.

v. Preparation of reserves estimates or reserves audits

1. 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?

   Answer: The Commission should require disclosure of whether the reserves were prepared internally or externally by independent petroleum consultants, but review of qualifications of reserves estimators and auditors should remain a control item within the company.

2. 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?

   Answer: These items should be items of internal controls, subject to audit verification. However, the Commission should allow, but not require, the disclosure of such information.

3. 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?

   Answer: As in Question (1) above, internal controls should be established and monitored by management and internal audit (and external audit, as established by law or practice) to ensure the objectivity and independence of in-house reserves estimators and auditors, as well as external reserves estimators and auditors.

4. 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?

   Answer: This should be a matter of internal controls and should be audited by both internal and external auditors for those controls. However, the Commission should allow, but not require, reporting of such material.

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

<u>Answer:</u> No, this disclosure should not be required. Please see the answer to Questions (3) and (4) above.

6. 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?

   <u>Answer:</u> No, this disclosure should not be required. Please see the answer to Questions (3) and (4) above.

7. 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?

   <u>Answer:</u> The Commission staff should have made available to it on request any such information, but the matter should remain an internal control.

8. 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?

   <u>Answer:</u> See the answer to Question (7) above.

9. 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?

   <u>Answer:</u> No, a third party should not be required to prepare or audit reserves audit under any circumstances. Disclosure of internal or external reserves preparation or audit should be disclosed, as noted in the answer to Question 3(v)(1) above.

10. 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?

    <u>Answer:</u> Please see the answer to Question (9) above.

vi. Contents of third party preparer and reserves audit reports

1. 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?

   <u>Answer:</u> The Commission should require companies to disclose identities of the third parties who have prepared or audited their reserves. The reports should not be filed as in total, but the letter report should be required in the filing. The full report contains proprietary information and should be available upon request from the Commission staff (but should be kept confidential).

2. 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?

   Answer: A third party report should contain at a minimum the items discussed in the Society of Petroleum Evaluation Engineers Recommended Evaluation Practice Number 1, "Elements of a Reserves Report" (SPEE REP #1), Sections 1 and 2 and the tabular data applicable to the summary levels required in the financial filing (total and country/region) in Section 3. Most of the letters accompanying evaluation reports from third parties include such information and can be incorporated into the filing. A copy of SPEE REP #1 is attached to this response.

3. 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?

   Answer: A reserves audit should follow the standards set in the Society of Petroleum Engineers "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" (SPE Auditing Standards), February 19, 2007, Article II.2.f. The minimum percentage of audited reserves should be left to the discretion of the management of the company, but that amount should be disclosed. The audit results should be available to the Commission staff upon request. If the third party performs only a process review as defined in the SPE Auditing Standards, Article II.2.h, then that fact should also be disclosed. In that case, references to appropriate classifications and quantities of reserves should not be allowed in the discussion of the third party results. Third party evaluations, whether they are prepared reserves, audited reserves, or process reviews, are done at the discretion of management, which remains responsible for the contents of the reserves data reported in any financial filing. Management is in the best position to determine whether such third party work is done and, if it is performed, how much of the reserves data should be evaluated by a third party.

4. 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?

   Answer: Please see the answer to Question (3) above. Management should make the decision on percentages and which particular fields or "geographic areas" are submitted for third party evaluation (whether that be auditing or preparation). The quantity of reserves examined by third parties, as well as the results of the examination, should be disclosed.

5. 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?

Answer: Please see the answers to the questions above in this section. This should not be confusing to investors if the percentage of reserves examined by a third party is disclosed, as well as the nature of the examination.

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

   Answer: The definition is appropriate with the exception of the 80% threshold. It is consistent with the SPE Auditing Standards.

vii. Solicitation of comments on process reviews

1. 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?

   Answer: Clear reporting of the scope of the third-party process (be it preparation, audit, or process review) should not confuse investors. Please see the answers to the questions in (vi) above.

2. The proposal does not prohibit disclosure of process reviews. 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?

   Answer: Clear reporting of the scope of the third-party process (be it preparation, audit, or process review) should not confuse investors. Please see the answers to the questions in (vi) above.

4. Proposed Item 1203 (Proved undeveloped reserves)

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

   Answer: Devon believes that the table could be useful information to investors. Companies should be required to reclassify their PUD reserves after five years if these reserves remain undeveloped unless there is a good, documented reason(s) for continuing to carry those proved undeveloped volumes.

2. 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?

   Answer: No, the table is sufficient disclosure. Including the other categories of changes would impose an onerous burden on companies.

3. 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?

   Answer: We can only speak for Devon, where we strictly adhere to our understanding of the rules and guidance pertaining to reserves disclosures. We are unable to predict the impact of the proposed rule on the practices of other companies.

4. 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?

   Answer: Reasons for maintaining proved undeveloped reserves for more than five years should be required only for material properties, i.e., properties with proved reserves that constitute more than 10% of the company's reported proved reserves.

5. 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?

   Answer: No, this disclosure should not be required. This could result in an intensive effort to gather the data required and would not be useful if done for all proved undeveloped reserves. Material proved undeveloped reserves that are not anticipated to be developed within five years should be explicitly identified and discussed. Material additions to proved undeveloped reserves should also be identified and discussed.

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

   Answer: Please see the answer to Question (5) above.

5. Proposed Item 1204 (Oil and gas production)

1. Should we adopt the proposed table?

   Answer: Tables for production as currently required and presented in the 10-K are more than adequate and disclose more information than the proposed table. The breakout should remain by country/region as it is done for reserves.

2. 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?

   Answer: The definition set forth in SFAS 69 (Paragraph 12) is sufficient and should be maintained.

3. 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.

   Answer: The instructions listed should be eliminated.

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

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

   Answer: No, these figures are generally disclosed in other information not subject to financial accounting guidelines. The information might be difficult to assemble in time for a financial report deadline.

2. 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?

   Answer: Although Devon recommends that no new disclosure of drilling activities be mandated, we do support the inclusion of two new well types. This will materially aid in accounting calculations.

7. Proposed Item 1206 (Present activities)

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

   Answer: No, these matters are generally discussed in the section "Management's Discussion and Analysis of Financial Condition and Results of Operations" (MD&A). No new disclosure requirement would be beneficial to investors.

2. 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?

   Answer: No, the disclosure requirements in Item 7 of Industry Guide 2 are sufficient.

8. Proposed Item 1207 (Delivery commitments)

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

   Answer: Yes. No substantive changes were noted.

2. 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?

   Answer: No.

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

   Answer: Yes. Fixed delivery commitments are still entered into by oil and gas companies and can be material for the respective company.

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

i. Enhanced description of properties disclosure requirement

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

   Answer: No, the present required disclosures are adequate to inform the investor of the status of oil and gas properties that comprise the reserves base of the company. The enhanced disclosure could become confusing to investors or could damage the competitive standing of a company by revealing areas of concentration.

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

   Answer: No, the disclosure referring to the entity in whole is sufficient to adequately inform investors. Reporting by country/region could be required as a sufficiently granular level if the Commission feels that more detail is warranted.

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

   Answer: No. the terms used are well known to those engaged in oil and gas activities.

ii. Wells and acreage

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

   Answer: No, the table required now as part of disclosure requirements is adequate to present necessary information to investors.

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

   Answer: No, the current requirement is adequate. Please see the answer to Question 9(i)(1) above.

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

   Answer: No; please see the answers to the questions on this topic above.

4. 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?

   Answer: Maintaining this disclosure requirement is acceptable.

iii. New proposed disclosures regarding extraction techniques and acreage

1. 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?

   Answer: The tables presenting reserves by product, as recommended above in Item B(2), are sufficient to indicate the extraction techniques that may be used to produce oil and gas. Discussions in the MD&A section should address material new additions that involve different extraction technologies.

2. 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?

Answer: See the answers to Item B(2) above; Devon recommends the disclosure of proved reserves only.

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

1. 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?

   Answer: Although the proposed item does not intend to increase a company's disclosure requirements, the result would be a significant increase in such disclosure requirements. Items concerning material additions and revisions to reported reserves should be addressed in the MD&A section, but this discussion should not require extensive new tables. In addition to the MD&A discussion, the recent move by the Commission staff to increase information on material properties (as prescribed by Regulation S-K) is sufficient to provide the necessary information to investors.

2. 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?

   Answer: No; see the answer to Question (1) above.

3. 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?

   Answer: The MD&A should be kept as a self-contained section.

IV. Proposed Conforming Changes to Form 20-F

Devon has no response to this section as we do not file this form.

V. Impact of Proposed Amendments on Accounting Literature

B. Change in Accounting Principle or Estimate

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

   Answer: We believe that the proposed changes are more properly characterized as a change in accounting estimate. We make reference to paragraph 20 of SFAS 154.

2. 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?

   Answer: As noted above, we believe the proposed changes are more properly characterized as a change in estimate.

3. 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?

   Answer: We would not have the historical data to determine the amount of retroactive revisions of prior years. The fact that quantities of reserves are estimates, regardless of what price or methodology is used to determine such quantities, implies that changes from the proposed new rules would be properly accounted for as changes in estimates. Accordingly, no retroactive revisions are necessary.

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

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

   Answer: We have no mining operations or specific knowledge of mining accounting rules and therefore cannot address this question.

2. 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?

   Answer: We have no mining operations or specific knowledge of mining accounting rules and therefore cannot address this question.

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

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

   Answer: We are not able to determine the materiality of historical amortization levels. Average prices may be either higher or lower than specific year-end prices, and therefore it is not possible to determine the impact of a change to the use of average prices.

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

   Answer: See our response to question 1 immediately above.

3. 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?

   Answer: As stated earlier in our response, we do not believe that it would be appropriate to use different prices for reserves estimates and amortization estimates. We believe that using two different pricing scenarios to determine two different quantities of reserves has a high likelihood of confusing investors and contradicts the principles of clarity and transparency in financial disclosures. The fact that using two different pricing scenarios would require the need to add disclosures to explain the inconsistencies, as evidenced by your questions above, reinforces our suggestion to use average prices to determine the quantities of reserves for all purposes, including accounting.

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

1. 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?

   Answer: It is appropriate to codify Industry Guide 2 separately from other industry guides, as the oil and gas disclosure regulation will be enhanced by the process.

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

   Answer: Devon does not believe that this codification will overrule or otherwise affect any other disclosures required in the other Industry Guides.

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

1. 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?

   Answer: At this point in the process, the Commission should not require the filing of oil and gas disclosures in interactive data format. However, if the Commission's proposed rule that requires financial statement information to be reported as interactive data using XBRL becomes final, then oil and gas disclosures included in such financial statement information should be reported as interactive data, too. The principal factor to consider in requiring interactive data formatting is the completion of a generally accepted taxonomy for oil and gas disclosures.

2. 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?

   Answer: If the interactive filing is required, a phase-in period should be established similar to the Commission's proposed phase-in for reporting financial statement information using XBRL. The phase-in process should begin only after a well-developed standard list of electronic tags has been created and available for use by the industry. The Commission could develop the standard taxonomy alone or with input from a voluntary submission program.

The development of products to load data into interactive programs for data analysis has been done by those analysts and companies that wish to do so. In time, a large number of companies would probably use interactive data voluntarily, although there is no guarantee of this result. However, companies are moving to electronic data formats in most of their business functions, so it is likely.

3. 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?

   Answer: Most companies would communicate their oil and gas disclosures in an interactive data format after they have released such data in a manual format in an earnings release. Assuming investors, analysts, and others would be willing to wait for the interactive data to use for data analysis purposes, then interactive data would be useful because it could be transferred more quickly and would probably result in fewer errors.

4. 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?

   Answer: The data is amenable to interactive format. Because oil and gas disclosures are core to the industry, development of a standard taxonomy for such disclosures is critical. Additionally, because the oil and gas disclosures are relatively standard, a standard taxonomy would eliminate the need for most taxonomy extensions and therefore result in fewer disclosure inconsistencies among companies. The standard taxonomy could be established by an independent group, such as the recommended RASB (see general comments in Item IX below), or by the Commission engineering and accounting staffs. The Society of Petroleum Engineers standard nomenclature is available for much of the reserves taxonomy.

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

   Answer: If interactive data is required, it would be useful for such data in the proposed tables to interact with other data in Commission filings. The most logical interaction would involve the same data, which must be disclosed in other sections of filings (i.e., financial statement information) and may be required to be reported in interactive data format as proposed by the Commission.

6. 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?

   Answer: We note that the Commission has proposed a requirement for companies to provide financial statement information in interactive format using XBRL. We assume that this proposed rule will become final in the near future. Based on this assumption, any requirement to provide oil and gas disclosures in an interactive data format should also require the use of XBRL for such interactive reporting. Requiring the same reporting language for both financial statement information and oil and gas disclosures would increase the efficiency of the reporting process. Data within Commission filings would likely interact more accurately and completely if the same reporting language were used.

VIII. Proposed Implementation Date

1. 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?

   Answer: Yes, a delayed compliance date is appropriate. Implementation will take some time, especially if the Commission adopts provisions to report unproved reserves and some of the tables proposed. The Commission should allow two reporting cycles (year-end 2009 and year-end 2010) to fully implement the changes.

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

   Answer: No, early compliance for year-end 2008 reserves should not be allowed.

IX. General Request for Comment

We request and encourage any interested person to submit comments regarding:

1. The proposed rule changes and additions that are the subject of this release;
2. Additional or different changes; or
3. Other matters that may have an effect on the proposals contained in this release.

Answer: Devon commends the Securities and Exchange Commission for the proposed changes in the oil and gas disclosure requirements and appreciates the opportunity to comment on those proposals. This move to amend the disclosure requirements is a milestone in rational reporting of oil and gas reserves data to concerned stakeholders in oil and gas companies that report under the Commission's regulations and guides.

Devon does recommend that required disclosures not be structured so as to become burdensome and has provided its feedback with respect to certain proposed tables and disclosures that would be burdensome if implemented. Extensive additional information (e.g., types of accumulations, types of wells) could require many more man-hours to prepare than the estimate provided by the Commission in its proposal. These man-hours are better used in finding and producing oil and natural gas.

Devon also notes that the Commission did not address the issue of an independent standards-setting body, which in the Devon comments to the "Concept Release on Possible Revisions to the Disclosure Requirements Relating to Oil and Gas Reserves" was entitled the Reserves Accounting Standards Board, or RASB. Such a group could be funded by industry, as is the Financial Accounting Standards Board. This group could establish the application guidelines for reasonable certainty (such as the requirements for proved undeveloped reserves that must all meet the standard of reasonable certainty) and the criteria for reliable technology.

X. Paperwork Reduction Act

D. Request for Comment

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.

Answer: Devon believes that the burden to collect the information in the current form of the proposed rules is significantly underestimated. This collection would become progressively less burdensome after several reporting cycles as electronic data collection efforts are built and improved, but initially this time could be in the thousands of man-hours.

XI. Cost-Benefit Analysis

E. Request for Comments

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.

Devon has no comment on this matter.

XIII. Initial Regulatory Flexibility Analysis

G. Solicitation of Comment

We encourage the submission of comments with respect to any aspect of this Initial Regulatory Flexibility Analysis. In particular, we request comments regarding: (i) the number of small entity issuers that may be affected by the proposed revisions; (ii) the existence or nature of the potential impact of the proposed revisions on small entity issuers discussed in the analysis; and (iii) how to quantify the impact of the proposed revisions. Commenters are asked to describe the nature of any impact and provide empirical data supporting the extent of the impact. Such comments will be considered in the preparation of the Final Regulatory Flexibility Analysis, if the proposed revisions are adopted, and will be placed in the same public file as comments on the proposed amendments.

Devon has no comment on this matter.