Society of Petroleum Engineers
Dallas • Dubai • Houston • Kuala Lumpur • London
www.spe.org

26 August 2008

To: Florence B. Harmon
Acting Secretary
Securities and Exchange Commission
File Number S7-15-08
Comments on Proposed Modernization of the Oil and Gas Reporting Requirements

The Society of Petroleum Engineers (SPE) commends the commission on a thorough review and balanced analysis of the replies to the December 2007 Concept Release. In the opinion of the SPE Oil and Gas Reserves Committee (OGRC), if the amended definitions were fully implemented as proposed, they would dramatically improve industry's ability to communicate the breadth and depth of their Reserves.

SPE is highly encouraged that the SEC's Proposal makes extensive reference to the internationally accepted petroleum resources categorization and classification standards contained in the 2007 Petroleum Resources Management System (PRMS), jointly sponsored by SPE, the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE).

SPE understands that to achieve consistency in regulatory disclosures, a principle-based system such as PRMS must be supplemented with supporting regulatory guidelines. SPE comments submitted herein are intended to further enhance specific sections of the Proposal based on the international consensus achieved in PRMS and the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" (Auditing Standards) as revised in March 2007. The Requests for Comments that are not addressed have been carefully considered by the OGRC and determined to fall outside SPE's guidance on Reserves and resources estimation contained within PRMS or the Auditing Standards. While technical estimation issues have been addressed, we offer no comment on the details of the disclosure content or format.

We note that the proposal is restricted to Reserves. SPE submits that all assessments benefit from explicit recognition of the larger context of the total resources classification, including Contingent and Prospective Resources, and the principles underlying classification and categorization as defined in PRMS. These key principles are:

- projects are first classified based on their chance of achieving commercial production. Reserves can only be attributed to those projects deemed economic and where there is no significant contingency that would prevent implementation of the project within a reasonable timeframe.

- the estimates of recoverable quantities to be derived from projects that meet the Reserves criteria are then categorized according to their relative uncertainty as Proved, Probable and Possible.

Under PRMS, each category, in general, meets the same project-based class criteria. Moreover, the project may be further characterized as Developed or Undeveloped based on facilities funding and operational status. The recovery uncertainty is independent of the Reserves status assigned; for example, Developed Reserves may be categorized as Proved, Probable and Possible.

In prior guidance, SEC disclosures were restricted to Proved Reserves. Some of that restrictive language has been carried over to the Proposed Rules. Many of SPE's suggested edits are intended to ensure that the principles contained in the Proposal apply equally to the optional Probable and Possible Reserves disclosures.

Respectfully,

William M. Cobb

William M. Cobb
2008 SPE President

cc: Delores James Hinkle, Chairperson, SPE Oil and Gas Reserves Committee

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

II.B. Year-End Pricing

II.B.1. 12-month average price

Request for Comment

- 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?

  PRMS considers the previous 12-month average price as the price at current conditions. Reserves evaluations are used to develop cash-flow-based economic scenarios. PRMS deems the standard to be use of a forecast of future economic conditions, including costs and prices, defined as the "forecast case" (implied as the "base case"). The use of current economic conditions held constant (no price and cost escalations, inflation, or deflation) during the entire project life is noted in PRMS as an alternative economic scenario. Use of a longer averaging period would be inconsistent with PRMS.

  If average pricing over the period of the previous year is selected, the volatility of seasonal variations is minimized. Shorter averaging periods can introduce volatility due to weather, market variability, and other factors. Longer averaging periods may result in long-term pricing trends being obscured.

- 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?

  As summarized in the immediately preceding question, SPE believes prices averaged over the previous one-year period is an appropriate method for estimating Reserves based on historical pricing unless prices are defined by contracts or property-specific hedge agreements.

  Use of forecast economic conditions (costs and prices) is the standard economic scenario, defined as "forecast case," for Reserves evaluations in PRMS. PRMS states that such forecasts must be clearly documented. Forecast prices should be tied to forecast costs to meet the PRMS guidance of future economic conditions. Thus, to use future prices in a forecast case, either the company must document its assumptions for future costs or the SEC must provide guidelines for future costs. If company assumptions are allowed without clear documentation, then potential inconsistencies among reporting companies will not be understood.

- 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 PRMS, the SPE does not take a position on how average price should be determined.

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

  SPE takes no position on disclosure issues. However, it should be noted that PRMS allows the use of multiple price scenarios to develop multiple Reserves and resources estimates.

II.C. Extraction of Bitumen and Other Non-Traditional Resources

Request for Comment

- 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?

  Consistent with PRMS, SPE supports that the development and production of unconventional petroleum resources (including but not necessarily limited to oil sands, oil shale, coalbed methane, and gas hydrates) be classified as oil and gas producing activities as proposed. While the assessment methods, extraction operations (including mining), and associated processing (including upgrading and conversion to synthetic crude oil and/or synthetic gas) may differ from those applied to conventional accumulations, the same reserves classification and categorization criteria apply.

  The PRMS definition of unconventional resources aligns with the SEC definition of continuous accumulations. The SPE strongly encourages the use of the PRMS terminology "unconventional" in preference to the proposed term "non-traditional" as it represents industry accepted terminology.

- 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.

SPE understands the dilemma where coal, although mined primarily for direct power generation, can be processed to generate natural gas (and hydrocarbon liquids). PRMS supports that coalbed methane extracted by wells is an oil and gas activity but has no guidance on mined coal.

SPE notes that closer alignment of the Reserves and resources estimation guidelines for petroleum and minerals may minimize the classification and reporting dilemma around fossil fuels such as coal.

- 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?

Under PRMS, the kerogen in oil shales is considered as immature petroleum and is treated in the same manner as bitumen in oil sands, which is considered as over-mature petroleum. Thus, SPE supports including extraction of oil shales, whether through in-situ processes or mining, as an oil and gas activity.

II.D. Reasonable Certainty and Proved Oil and Gas Reserves

Request for Comment

- 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?

SPE offers the following guidance on "Reasonable Certainty":

- If deterministic methods are used, reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered.
- If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

- 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?

The 90% threshold is consistent with PRMS, and SPE considers it appropriate.

II.D.1. New technology

Request for Comment

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

SPE considers "reliable technology," being defined as "field tested and has demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation," to be broadly consistent with PRMS requirements for documentation of the geoscience and engineering analysis used to develop the Reserves estimates.

SPE is unclear on the exact meaning of the term "correct conclusions in 90% or more of its applications." We strongly urge the SEC to provide additional clarity around the exact meaning of the requirement. It is the view of SPE this requirement is ambiguous and, as currently written, would be impossible to fulfill.

- 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?

The definition itself must stay open-ended to a certain extent to accommodate future development. PRMS places the burden on the estimator to sufficiently document the rationale for applying a given technology.

II.D.2. Probabilistic methods

Request for Comment

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

  SPE considers the proposed definitions, which are consistent with PRMS, appropriate.

- 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?

  SPE considers the statements appropriate, assuming acceptance of our suggested revisions to the definitions of "Reasonable Certainty," Section II.D.

- 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?

  Consistent with PRMS, SPE supports the use of either deterministic or probabilistic estimation methodologies.

II.D.3. Other revisions related to proved oil and gas reserves

Request for Comment

- 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?

  PRMS supports the use of technologies that do not provide direct information in determination of Reserves volumes, subject to our comments in Section II.D.

- 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?

  PRMS does not require that project financing be confirmed prior to classifying projects as Reserves.

II.E. Unproved Reserves—"Probable Reserves" and "Possible Reserves"

Request for Comment

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

  SPE does not promote a specific position on disclosure requirements. We generally support the proposed definitions of Probable and Possible Reserves, as they are broadly consistent with PRMS, but suggest the clarifications noted in the response to the next question.

- 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?

  SPE recommends the following additions to the definitions of Probable and Possible Reserves. We have included a revised text of the proposal to provide clarity to the readers regarding the foundation for the relationship between incremental and scenario evaluations.

  "When assessing the amount of oil and gas that is recoverable from a project, a company can make three scenario estimates of the quantity of oil and gas that is recoverable:

  - A low estimate that is reasonably certain;
  - A best estimate that is as likely as not to be achieved but less likely to occur than the low estimate
  - A high estimate that might be achieved, but only under more favorable circumstances that are less likely to occur than for the best estimate.

The same assessment can alternatively be expressed in terms of the standard incremental Reserves categories of Proved, Probable and Possible where the *Low Estimate* is Proved, the *Best Estimate* is Proved plus Probable, and the *High Estimate* is Proved plus Probable plus Possible. Use of all categories of Reserves determined to be commercial (passing both the economic and the commitment criterion) reflects the relative uncertainty inherent in estimating recoverable quantities."

- 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?

SPE supports the 50% and 10% thresholds, which are consistent with PRMS.

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

Request for Comment

- 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?

PRMS defines Developed Reserves as expected quantities to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or ***when the costs to do so are relatively minor compared to the cost of a well.*** As outlined in PRMS, the terms "Developed" and "Undeveloped" apply to all Reserves categories.

II.G. Definition of "Proved Undeveloped Reserves"

II.G.1. Proposed replacement of certainty threshold

Request for Comment

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

SPE believes that the proposed extension of the concept of reasonable certainty and the ability to apply reliable technology in the assessment of Proved Undeveloped Reserves, with the proviso that the terms "Developed" and "Undeveloped" apply to all Reserves categories as well as the recognition of recommended modifications presented in the proposed addendum Glossary, are consistent with PRMS and are very important improvements that will enhance the consistency between the Proved Developed and Undeveloped categories.

As stated in the PRMS, there must be a firm intention to proceed with development based on all of the criteria noted to classify quantities as Proved Undeveloped.

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

SPE supports a principle-based system as proposed. PRMS supports that reasonable certainty is established through the application of professional experience in the assessment of all engineering and geoscience data that is available and should not be arbitrarily limited to a predetermined area. The application of professional experience in making a judgment of reasonable certainty of economic producibility up to a justifiable distance (versus "any distance") from productive units would be determined by the evidence gathered from reliable technology.

SPE notes that the Proposed Regulations contain references to the term "drilling units," which is not globally accepted oil and gas terminology. We encourage the SEC to adopt language that is more globally accepted such as "drainage area."

- 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?

PRMS states: "Where Reserves remain Undeveloped beyond a reasonable timeframe, or have remained Undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in ***initiating development*** and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay is justified, a reasonable time frame is generally considered to be less than five years." Note that the PRMS guidance applies to Reserves of all categories.

Large, complex projects or those with very long productive lives may take considerably longer than 5 years to fully develop. Consequently, the SPE believes that establishing a blanket arbitrary time limit is not appropriate for these types of projects. It is incumbent on the evaluator to document the rationale for scheduling Undeveloped reserves for development beyond five years.

- 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?

The SPE believes that it would be difficult to develop a comprehensive list of legitimate circumstances for carrying Proved Undeveloped reserves for periods longer than five years. Each case needs to be considered on its specific facts and circumstances.

II.G.2. Proposed definitions for continuous and conventional accumulations

Request for Comment

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

SPE notes that in the Proposed Regulations, the definition of "continuous accumulations" is an acceptable equivalent to the PRMS definition of "Unconventional Resources."

- 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?

Note previous response.

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

Note previous response.

II.G.3. Proposed treatment of improved recovery projects

Request for Comment

- 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?

    PRMS states that improved recovery projects may be supported by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied. It is important to note that PRMS does not contain the ***"immediate area"*** restriction included in the Proposed Regulations. To maintain consistency SPE recommends removal of the term "immediate area."

II.H. Proposed Definition of Reserves

Request for Comment

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

    Consistent with PRMS guidance, we offer the following as a definition of "Reserves":

    Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be recoverable, as of a given date, by application of development projects to known accumulations. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Commercial, in this context, means that in addition to economic producibility at current prices and costs, there exists, or there is reasonable expectation that there will exist, the legal right to produce (including other non-operated or revenue interest in the production), installed means of delivering oil and gas, or related substances to market, and all permits and financing required to implement the project. Production and sales are normally measured and reported in terms of the quantities crossing a specified reference point (terminal point) over the specified period. Reserves are categorized as Proved, Probable, and Possible according to the degree of uncertainty associated with the estimates of recoverable quantities.

II.I. Other Proposed Definitions and Reorganization of Definitions

Request for Comment

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

  In general SPE finds the proposed definitions are aligned with PRMS terms. However, we find some situations where defined terms should be reviewed for further clarity or some terms used in your Proposal text have not been defined. We have provided our suggestions for a complete set of defined terms in the addendum Glossary, including the definitions of some terms introduced in revised language suggested by SPE.

- 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?

  Suggested edits to the definitions in the proposed regulations are offered primarily to ensure accommodation of optional Probable and Possible Reserve disclosures. Note that under PRMS, Developed and Undeveloped indicate Reserves status and apply to all Reserves categories. Additional definitions, based on the PRMS glossary, are proposed to clarify terms used within the proposed regulations. The proposed addendum Glossary is modeled on PRMS where definitions have been broadly reviewed and endorsed by the petroleum industry.

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

  SPE strongly recommends that the final SEC regulations include an extended, alphabetized glossary of all terms used in the proposal to ensure clarity. Such a glossary of standard terminology is required to support consistent Reserves estimates.

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

III.B.3. Proposed Item 1202 (Disclosure of reserves)

III.B.3.i. Oil and gas reserves tables

Request for Comment

- 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?

While the SPE takes no position on specific disclosure requirements, the following information is based on guidance given in the PRMS regarding Reserves reporting.

Under the deterministic incremental approach, quantities at successive increasing levels of uncertainty/decreasing levels of confidence (Proved, Probable, Possible) are estimated discretely. Under the deterministic scenario approach, quantities at each level of uncertainty are estimated compositely. Successive cumulative estimates (Proved, Proved plus Probable, Proved plus Probably plus Possible) have increasing uncertainty. The incremental and scenario approaches use the same deterministic technical guidelines.

Uncertainty in resource estimates is best communicated by reporting the full range of potential results. Companies consider multiple scenario outcomes in formulating development plans and evaluating associated project production and cash flow schedules. It is on this basis that project investments decisions are made.

Proved Reserves (1P) represents the low estimate scenario outcome and is typically not used alone for investment decisions. The Proved plus Probable plus Possible (3P) scenario incorporates upside potential. If it is required to report a single representative result, the sum of Proved and Probable (2P) is considered the "best estimate" and the most likely scenario outcome. Best practice is to consider at least these three scenarios in project evaluations.

When probabilistic assessment methods are used, uncertainty thresholds (P90/P50/P10) are defined for each cumulative Reserves grouping (1P, 2P, 3P). While deterministic estimates may have broadly inferred confidence levels, they do not have associated quantitatively defined probabilities. Nevertheless, the ranges of the probability guidelines established for the probabilistic method broadly correlate to the amount of uncertainty generally inferred in the estimate derived from the deterministic method.

SPE notes that the Proposed Regulations may result in confusion between the terms "risk" and "uncertainty" that should be clarified.

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

While SPE takes no position on specific disclosure requirements, the following information is based on guidance given in the PRMS regarding risk and uncertainty in Reserves assessment.

Under PRMS, "risk" in the resource classification is the chance that a project will not be commercially developed. By definition, Reserves are only attributed to projects that have a very high certainty of being developed. "Confidence level" or "confidence factor" is a more rigorous term to describe increasing uncertainty in Probable and Possible Reserves estimates. It is appropriate for evaluators to provide a text summary of the key issues related to the category definitions that were considered in assigning quantities to Probable and Possible Reserves.

- 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?

While SPE takes no position on specific disclosure requirements, the following information is based on guidance given in the PRMS regarding reporting Reserves estimation. PRMS endorses expressing Reserves estimates as either discrete incremental estimates (Proved, Probable and Possible) or cumulative scenario estimates (Proved (1P), Proved plus Probable (2P), Proved plus Probable plus Possible (3P)). The category definitions in the proposed addendum Glossary align with PRMS and provide sufficient clarity on the relative uncertainties associated with each reported estimate.

In probabilistic analysis, the uncertainty limits associated with the 1P, 2P and 3P estimates are defined by convention. The quantitative confidence factors associated with discrete incremental estimates are not defined. In deterministic analysis, the low, best and high cases are presumed to be broadly equivalent to 1P, 2P and 3P respectively. Therefore, from a PRMS perspective, cumulative estimates would give the best understanding of overall volumes, because they accommodate both deterministic and probabilistic approaches.

As noted above, the sum of Proved plus Probable is considered the best estimate of Reserves and is typically assigned greater weighting by companies in formulating business decisions.

- 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?

While SPE takes no position on specific disclosure requirements, the following information is based on guidance given in the PRMS regarding reporting Reserves estimation.

It is critical that any Reserves report clearly identifies the basic Reserves entity level at which uncertainty in estimates is assessed. PRMS recognizes that it is appropriate to assess uncertainty in estimates of recoverable volumes at the property, field, or project level.

Under PRMS guidelines, it is not allowed to aggregate reserves probabilistically to the company reporting level but only to the field, property or project level. All subsequent aggregations including geographic reporting should use arithmetic summation.

The divergence between arithmetic summation and probabilistic aggregation can be very significant for both Proved (1P) and Proved plus Probable plus Possible (3P) estimates where there is substantial independence between reserves entities being aggregated. Arithmetic summations of Proved plus Probable plus Possible (3P) estimates will yield extremely optimistic company and country totals in large portfolios of fields/projects; such summations may raise public expectations around results that have minimal chance of occurring. This is the same statistical effect that makes arithmetic summations of Proved Reserves extremely conservative. The divergence around Proved plus Probable (2P) is less dramatic as the P50 approaches the statistical mean of the distribution at the Reserves entity level. Since, under the central limit theorem, the "sum of the means is equivalent to the mean of the sums", any divergence between deterministic summations and probabilistic aggregations for 2P reporting at country and company aggregate levels will be comparatively minimal.

In summary, under PRMS guidance, reported Reserves assessment results should not incorporate statistical aggregation beyond the field, property, or project level. Results reporting beyond this level should use arithmetic summation by Reserves category but should include the caution that the aggregate Proved may be a very conservative estimate and aggregate Proved plus Probable plus Possible may be very optimistic depending on the number and diversity of items in the aggregate. Summations of Proved plus Probable results are typically less distorted by statistical aggregation effects.

III.B.3v. Preparation of reserves estimates or reserves audits

Request for Comments

- 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?

SPE recently updated its publication "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" after careful review and consultation with industry experts with recognition of the increased global emphasis on improving corporate governance practices. In recognition that the petroleum industry relies on increasingly complex technology and the need for cooperation between geoscience and engineering disciplines, SPE recommended minimum training and experience levels for both reserves estimators and reserves auditors. SPE's Auditing Standards do not require mandatory licensure. Inconsistency between countries, states and professional societies reduce licensure effectiveness, while licensure requirements could pose an extreme challenge in terms of legal obligations, cost, access and implementation. These standards also include continuing training in ethics as a basic requirement.

III.B.4. Proposed Item 1203 (Proved undeveloped reserves)

Request for Comment

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

PRMS recognizes that large, complex projects are routinely developed over periods much longer than five years and that companies should not be required to reclassify PUDs after an arbitrary period of time if proper review and documentation of reasons for the longer periods exist. Please refer to our comments in Section II.G.1.

IX. General Request for Comment

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

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

We request comment from the point of view of registrants, investors, and other users of information about the disclosures that should be required with regard to oil and gas companies and the corresponding definitions of terms used in those disclosure requirements.

SPE identified the following issues that were addressed in PRMS and where additional guidance in the SEC Proposal may be required to ensure clarity and consistency in Reserves reporting:

Reserves Definitions, Reference Point, and Pricing:

Under PRMS, Reference Point (equivalent to SEC Terminal Point) is a defined location where produced quantities are measured. The Reference Point is typically the point of sale to third parties or where custody is transferred to the entity's downstream operations. Sales quantities are normally measured in terms of volumes crossing this point over the period of interest.

SPE agrees that Reserves quantities should be stated in terms of the "natural product" as derived from the extraction activity but notes that pricing information may not be available for the product at this point in the value chain in highly integrated production/processing projects. SPE supports the use of "transfer" or "netback" prices to define economic limits for supplemental assessment of Reserves in these cases. Additional guidance may be required to provide clarity and consistency to defining economic producibility. .

Consideration should be given to the following principles from PRMS:

- The "sales" (marketable) products are in the condition as specified at the custody transfer (terminal) point for pricing (e.g., limits for inclusion of non-hydrocarbons)
- The Reserves estimates are provided using these same product specifications
- Operating costs may be reduced, and thus project life extended, by various cost-reduction and revenue-enhancement approaches,

such as sharing of production facilities, pooling maintenance contracts, or marketing of associated non-hydrocarbons

- For consistency, lease fuel should be treated as shrinkage and is not included in sales quantities or Reserves estimates. However, PRMS recognizes that some regulatory guidelines allow lease fuel to be included in Reserves estimates where it replaces alternative sources of fuel and/or power that would be purchased in their absence. Where claimed as Reserves, PRMS recommends that such fuel quantities should be reported separately from sales and their value should be included as an operating expense. The inclusion of lease fuel as reserves is not inconsistent with PRMS guidance.

- If within the year, product prices are depressed for several months so as to make operations temporarily uneconomic, but the 12-month average price is sufficient to underpin economic production, Reserves may still be reported with supporting documentation of the circumstances.

- Where gas contracts or production is contractually linked to a specific property or project, these prices may be substituted for the 12-month average reserves prices.

Original Location/Gas Re-Injection

SPE recognizes an inconsistency in the treatment of re-injected gas in the Proposal when compared to PRMS and to prior SEC guidance. Specifically, in Section II.C, the Proposal states that: "Once a resource is extracted from the ground, it should not be considered oil and gas Reserves."

For a variety of reasons, gas is routinely extracted, processed and re-injected using common facilities. It can be re-injected into the same reservoir or into other reservoirs located on the same property for recycling, pressure maintenance, miscible injection, or other enhanced oil recovery processes. PRMS allows transfers between reservoirs without recording "production" as there are no sales involved. Gas Reserves should be reduced for losses associated with the re-injection and subsequent recovery process. Gas volumes injected into a reservoir for gas disposal with no committed plan for recovery are not classified as Reserves. Likewise, gas volumes purchased for injection and later recovered are not classified as Reserves.

Royalties/Reserves Entitlements

SPE suggests clarifications on the recognition of Reserves and their allocation based on entitlements to future production. This allocation is governed by the applicable contracts between the mineral owners (lessors) and contractors (lessees) and is generally referred to as "entitlement." PRMS recognizes the following regarding Reserves allocation and recognition:

- Reserves estimates must be reduced by royalties owing to others whether taken in kind or sold on behalf of the mineral owners.
- Conversely, if a company owns a royalty or equivalent interest of any type in a project, the related quantities can be included in Reserves entitlements.

XV. Statutory Basis and Text of Proposed Amendments.

§ 210.4-10 Financial accounting and reporting for oil and gas producing activities pursuant to the Federal securities laws and the Energy Policy and Conservation Act of 1975.

(a) Definitions

SPE strongly recommends that the final SEC regulations include an extended, alphabetized glossary of terms to support consistent Reserve reporting.

The Appendix A glossary is modeled on PRMS where definitions have been broadly reviewed and endorsed by the petroleum industry.

Appendix A includes:

1) 210.4-10 definitions with suggested edits.
2) clarification of terminology used within 210.4-10.
3) definitions of terms used in the Proposal with SPE suggested additions and amendments.

Appendix A:

Glossary of Terminology used in Oil and Gas Reserves Disclosures

SEC Proposed Definitions (sections II.I and XV) ***SPE recommended edits and additions from PRMS***
Aggregation. *The process of summing reservoir (or project) level estimates of resource quantities to higher levels or combinations such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.*
Accumulation. *An individual body of naturally occurring petroleum in a reservoir.*
Acquisition of properties [210.4-10 (a) (1)]. Costs incurred to purchase, lease, or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, broker's fees, recording fees, legal costs, and other costs incurred in acquiring properties.
Analogous reservoir. *Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery.* *When used to support Proved Reserves*, an **"analogous formation [210.4-10 (a) (2)]** ~~in the immediate area~~" refers to a formation that shares the following characteristics with the formation of interest: (i) Same geological formation; (ii) Same environment of deposition; (iii) Similar geological structure; and (iv) Same drive mechanism. Instruction to paragraph (a)(2): Reservoir properties must be no more favorable in the analog than in the formation of interest. ~~*When the geological properties change, the proposed analog formation can no longer be said to be an analogous formation in the immediate area of the formation of interest.*~~
Best estimate. *With respect to resource categorization, this is considered to be the best estimate of the quantity that will actually be recovered from the accumulation by the project. It is the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.*
***Bitumen. (see** Natural Bitumen)*
Coal bed methane (CBM). *Natural gas contained in coal deposits, whether or not stored in gaseous phase. Coal bed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. (also termed Coal Seam Gas - CSG or Natural Gas from Coal - NGC)*
Commercial *When a project is commercial, this implies that the essential social, environmental and economic conditions are met, including political, legal, regulatory and contractual conditions. In addition a project is commercial if the degree of commitment is such that the accumulation is expected to be developed and placed on production within a reasonable time frame.*

Condensate **[210.4-10 (a) (3)].** *A* mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.
Continuous accumulations **[210.4-10 (a) (4)].** Continuous accumulations are resources that are pervasive throughout large areas, have ill-defined boundaries, and typically lack or are unaffected by hydrocarbon-water contacts near the base of the accumulation. Examples include, but are not limited to, natural bitumen (oil sands), gas hydrates, and self-sourced accumulations such as coalbed methane, shale gas, and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g. removal of water from coalbed methane accumulations, large fracturing programs for shale gas, steam, or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining methods. (Moreover, the extracted oil or gas may require significant processing prior to sale (e.g. bitumen upgraders).
Conventional accumulations **[210.4-10 (a) (5)].** Conventional accumulations are discrete oil or gas resources related to localized geological structural features or stratigraphic conditions, with the accumulation typically bounded by a hydrocarbon-water contact near its base, and which are significantly affected by the tendency of lighter hydrocarbons to "float" or accumulate above heavier water.
Crude Oil. *Crude Oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature. Crude Oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas. (also termed "Oil")*
Deterministic estimate **[210.4-10 (a) (6)].** The method of estimating Reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the Reserves calculation is used in the Reserves estimation procedure.
Development cost **[210.4-10 (a) (7)].** Costs incurred to obtain access to ~~proved~~ Reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) Gain access to and prepare locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the ~~proved~~ Reserves. (ii) Drill and equip development wells, development-type stratigraphic wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and wellhead assembly. (iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems. **(iv)** Provide improved recovery systems.
Development project **[210.4-10 (a) (8)].** A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.
Development well **[210.4-10 (a) (9)].** A well drilled within the ~~proved~~ area of an oil or gas reservoir to a depth or a stratigraphic horizon known-to-be-productive.

Economically producible [210.4-10 (a) (10)]. The term economically producible, as it relates to a resource means a resource which generates revenue that exceeds, or is reasonably expected to exceed, costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

Estimated ultimate recovery (EUR) [210.4-10 (a) (11)]. Estimated ultimate recovery is the sum of Reserves remaining as of a given date and cumulative production as of that date.

Exploration Costs [210.4-10 (a) (12)]. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas Reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

Exploratory well [210.4-10 (a) (13)]. A well drilled to find a ***new field*** ~~***and produce oil or gas in an unproved area***~~ or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

Extension well [210.4-10 (a) (14)]. A well drilled to extend the limits of a known ~~proved~~ reservoir.

Field [210.4-10 (a) (15)]. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structure feature and/or stratigraphic condition. There may be ***two or*** more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geological barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single common operational field. The geological terms "structural features" and "stratigraphic conditions" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, area of interest, etc.

Gas hydrates. *Gas hydrates are naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure, or clathrate. At conditions of standard temperature and pressure (STP), one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas.*

High estimate. *With respect to resource categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.*

Hydrocarbons. *Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon. (see also Petroleum)*

Improved recovery. *Improved Recovery is the extraction of additional petroleum, beyond Primary Recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in situ mobility of viscous forms of petroleum. (also called Enhanced Recovery)*

Incremental estimates. *Relative uncertainty in deterministic Reserves estimates is expressed using standard incremental category terms: Proved, Probable and Possible.*

Kerogen. *The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called natural bitumen).*

Known accumulation. *The key requirement to consider an accumulation as "known", and hence containing Reserves is that it must have been discovered, that is, penetrated by a well that has established through testing, sampling or logging the existence of a significant quantity of recoverable hydrocarbons. A known accumulation may contain one or more known reservoirs.*

Lease Fuel. *Oil and/or gas used for field and processing plant operations. For consistency quantities consumed as lease fuel should be treated as shrinkage. However, regulatory guidelines may allow lease fuel to be included in Reserves estimates. Where claimed as Reserves, such fuel quantities should be reported separately from sales and their value must be included as an operating expense.*

Low estimate. *With respect to resource categorization, this is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.*

Marketable Hydrocarbons. The term "marketable hydrocarbons" means hydrocarbons for which there is a market for the product in the state in which the hydrocarbons are delivered. *All recoverable resources are estimated in terms of the product sales quantity measurements with defined specifications and measurement conditions. (see also Salable Product)*

Natural Bitumen. *Natural Bitumen is the portion of petroleum that exists in the semi-solid or solid phase in natural deposits. In its natural state it usually contains sulfur, metals and other non-hydrocarbons. Natural Bitumen has a viscosity greater than 10,000 milliPascals per second (mPa.s) (or centipoises) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis.*

Natural gas. *Natural Gas is the portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural Gas may include some amount of non-hydrocarbons. (also termed "Gas")*

Non-Hydrocarbon. *Oil and gas production often includes natural occurring associated gases (e.g. nitrogen, carbon dioxide, hydrogen sulfide, and helium) or small concentrations of metals. The Reserves and production should reflect only the residual hydrocarbon product and that portion of non-hydrocarbons defined in delivery specifications.*

Oil and gas producing activities [210.4-10 (a) (16)].

(i) Oil and gas producing activities include:
(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from ~~existing reservoirs on~~ such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of marketable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which can be upgraded into natural or synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as terminating at the first point at which:
a. Oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of marketable hydrocarbons that can be upgraded into natural or synthetic oil or gas, the marketable hydrocarbons are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas from the natural resources.

For purposes of this paragraph (a)(16), the term "marketable hydrocarbons" means hydrocarbons for which there is a market for the product in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:
(A) Transporting, refining, processing (other than field processing of gas to extract liquid hydrocarbons), or marketing oil and gas;
3) Activities relating to the production of natural resources other than oil, gas, or natural resources from whichnatural or nthetic oil and gas can be extracted; or
C) Production of geothermal steam.

Oil sand. *Sand deposits highly saturated with natural bitumen. Also called "Tar Sands". Note that in deposits such as the western Canada "oil sands", significant quantities of natural bitumen may be hosted in a range of lithologies including siltstones and carbonates.*

Oil shales. *Shale, siltstone and marl deposits highly saturated with kerogen. Whether extracted by mining or in situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil).*

Petroleum. *Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, or sulfur. In rare cases non-hydrocarbon content could be greater than 50%.*

Possible Reserves [210.4-10 (a) (17)]. Possible Reserves are those additional Reserves that are less certain to be recovered than Probable Reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding Proved plus Probable plus Possible Reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the Proved plus Probable plus Possible Reserves estimates.

(ii) Possible Reserves may be assigned to areas of a reservoir adjacent to Probable Reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible Reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for Probable Reserves.

(iv) The Proved plus Probable and Proved plus Probable plus Possible Reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher or lower than the Proved area if these areas are in communication with the Proved reservoir.

(vi) Pursuant to paragraph (a)(24)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, Proved oil Reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Probable Reserves [210.4-10 (a) (18)]. Probable Reserves are those additional Reserves that are less certain to be recovered than Proved Reserves but which, together with Proved Reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated Proved plus Probable Reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the Proved plus Probable Reserves estimates.

(ii) Probable Reserves may be assigned to areas of a reservoir adjacent to Proved Reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion.

(iii) Probable Reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for Proved Reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) through (a)(17)(vi) (Possible Reserves) of this section.

Probabilistic estimate [210.4-10 (a) (19)]. The method of estimation of Reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience, engineering, and economic data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Production costs [210.4-10 (a) (20)].

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to Proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

Proved area [210.4-10 (a) (21)]. That part of a property to which Proved Reserves have been attributed.

~~Proved developed~~ Developed oil and gas Reserves [210.4-10 (a) (22)]. ~~Proved~~ Developed oil and gas Reserves are ~~proved~~ Reserves ***of any category*** that can be expected to be recovered:

(i) In projects that extract oil and gas through wells, through existing wells with existing equipment and operating methods ***or the cost of the required equipment is relatively minor compared to the cost of a new well***; and

(ii) In projects that extract oil and gas in other ways, through installed extraction technology operational at the time of the Reserves estimate ~~or the cost of the required equipment is relatively minor.~~

Proved Properties [210.4-10 (a) (23)]. Properties with Proved Reserves.

Proved oil and gas Reserves [210.4-10 (a) (24)]. Proved oil and gas Reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as Proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, Proved oil Reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establishes the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the Proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous formation in the immediate area, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the ending price for each month within such period.

~~Proved undeveloped~~ Undeveloped* Reserves [210.4-10 (a) (25)]**. *~~Proved~~ Undeveloped oil* and gas Reserves are Reserves ***of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to ~~those drilling units~~ directly offsetting drainage areas ~~productive units~~ that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(A) In a conventional accumulation, offsetting drainage areas ~~productive units~~ must lie within an area in which economic producibility has been established by reliable technology to be reasonably certain.

(B) Proved Reserves can be claimed in a conventional or continuous accumulation in a given area in which engineering, geoscience, and economic data, including actual drilling statistics in the area, and reliable technology show that, with reasonable certainty, economic producibility exists beyond immediately offsetting ~~drilling units~~ drainage areas.

(ii) Undrilled locations can be classified as having ***~~proved~~*** Undeveloped Reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless unusual circumstances justify a longer time.

(iii) Under no circumstances shall estimates for ***~~proved~~*** Undeveloped Reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the area and in the same reservoir or an analogous reservoir in the same geologic formation in the immediate area or by other evidence using reliable technology establishing reasonable certainty.

Reasonable certainty [210.4-10 (a) (26)]. ~~When deterministic methods are used, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase than to either decrease or remain constant. When probabilistic methods are used, reasonable certainty means that there is at least a 90% probability that the quantities actually recovered will equal or exceed the stated volume.~~ ***~~As changes are made to estimated ultimate recovery (EUR) with time due to increased availability of geoscience, engineering, and economic data, then:~~***

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Reliable technology [210.4-10 (a) (27)]. Reliable technology is technology (including computational methods) that, when applied using high quality geoscience and engineering data, is widely accepted within the oil and gas industry, has been field tested and has demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation. Expressed in probabilistic terms, reliable technology has been proved empirically to lead to correct conclusions in 90% or more of its applications.

Reserves [210.4-10 (a) (28)]. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be recoverable, as of a given date, by application of development projects to known accumulations. ~~based on: analysis of geoscience and engineering data; the use of technology appropriate to establish the degree of certainty of the Reserves; the legal right to produce; installed means of delivering the oil, gas, or related substances to markets, or the permits, financing, and the appropriate level of certainty (reasonable certainty, as likely as not, or possible but not likely) to do so; and economic producibility at current prices and costs.~~ *Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Commercial, in this context, means that in addition to economic producibility at current prices and costs, there exists, or there is reasonable expectation that there will exist, the legal right to produce, installed means of delivering oil and gas, or related substances to market, and all permits and financing required to implement the project.* The volumes of Reserves shall be determined on the basis of their volumes at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section. Reserves are *categorized* ~~classified~~ as Proved, Probable, and Possible according to the degree of uncertainty associated with the estimates *of recoverable quantities*.

Note to paragraph (a)(28): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain Prospective Resources (potentially recoverable resources from undiscovered accumulations).

Reservoir [210.4-10 (a) (29)]. For conventional accumulations: a porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resources [210.4-10 (a) (30)]. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

Royalty. *Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs and the producer (lessee/contractor) for having access to the petroleum resources. Many agreements allow for the producer to lift the royalty volumes, sell them on behalf of the royalty owner, and pay the proceeds to the owner. Some agreements provide for the royalty to be taken only in kind by the royalty owner.*

Salable product. *The quantity of petroleum product delivered at the custody transfer (terminal) point with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities. All Reserves are estimated in terms of the product sales quantity measurements. (see also "Marketable Hydrocarbon")*

Scenario estimates. *The range of uncertainty of the recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When using the deterministic scenario method, typically there should also be low, best and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Alternatively Reserves may be expressed in incremental categories such that the low estimate is Proved, the best estimate is Proved plus Probable, and the high estimate is Proved plus Probable plus Possible.*

Sedimentary basin [210.4-10 (a) (31)]. ~~A sedimentary basin is a low area in the crust of the earth in which sediments have accumulated.~~ ***Sedimentary basins are areas of prolonged subsidence in the crust of the earth in which sediments accumulated.*** ~~Frequently, sedimentary basins that contain oil and gas reserves contain a number of discrete oil and gas reservoirs.~~

Service well [210.4-10 (a) (32)]. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes for service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

Stratigraphic test well [210.4-10 (a) (33)]. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as (i) "exploratory type" if not drilled in a known ~~proved~~ area or (ii) "development type" if drilled in a known ~~proved~~ area.
Synthetic crude oil (SCO). *A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. SCO may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil.*
Terminal point. The oil and gas production function shall be regarded as terminating at the first point at which: a) Oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and b) In the case of marketable hydrocarbons that can be upgraded into natural or synthetic oil or gas, the marketable hydrocarbons are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas from the natural resources.
Unproved Properties [210.4-10 (a) (34)]. Properties with no Proved Reserves.