Significant Differences in Proved Reserves Estimates Using SPE/WPC Definitions Compared to United States Securities and Exchange Commission Definitions

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Summary
A casual reading of the SPE/WPC (World Petroleum Congresses) Petroleum Reserves Definitions (1997) and the U.S. Securities and Exchange Commission (SEC) definitions (1978) would suggest very little, if any, difference in the quantities of proved hydrocarbon reserves estimated under those two classification systems. The differences in many circumstances for both volumetric and performance-based estimates may be small.

In 1999, the SEC began to increase its review process, seeking greater understanding and compliance with its oil and gas reserves reporting requirements. The agency’s definitions had been promulgated in 1978 in connection with the Energy Policy and Conservation Act of 1975 and at a time when most publicly owned oil and gas companies and their reserves were located in the United States. Oil and gas prices were relatively stable, and virtually all natural gas was marketed through long-term contracts at fixed or determinable prices. Development drilling was subject to well-spacing regulations as established through field rules set by state agencies.

Reservoir-evaluation technology has advanced far beyond that used in 1978; production-sharing contracts were uncommon then, and probabilistic reserves assessment was not widely recognized or appreciated in the U.S. These changes in industry practice plus many other considerations have created problems in adapting the 1978 vintage definitions to the technical and commercial realities of the 21st century.

This paper presents several real-world examples of how the SEC engineering staff has updated its approach to reserves assessment as well as numerous remaining unresolved areas of concern. These remaining issues are important, can lead to significant differences in reported quantities and values, and may result in questions about the “full disclosure” obligations to the SEC.

Introduction
For virtually all oil and gas producers, their company assets are the hydrocarbon reserves that they own through various forms of mineral interests, licensing agreements, or other contracts and that produce revenues from production and sale. Reserves are almost always reported as static quantities as of a specific date and classified into one or more categories to describe the uncertainty and production status associated with each category. The economic value of these reserves is a direct function of how the quantities are to be produced and sold over the physical or contract lives of the properties.

Reserves owned by private and publicly owned companies are always assumed to be those quantities of oil and gas that can be produced and sold at a profit under assumed future prices and costs. Reserves under the control of state-owned or national oil companies may reflect quantities that exceed those deemed profitable under the commercial terms typically imposed on private or publicly owned companies.

Background of Relevant Reserves Definitions. Table 1 illustrates the genesis and development of petroleum reserves definitions in the U.S. through 1981, including the WPC since 1983. The WPC comprises approximately 59 petroleum-producing countries and has been a major contributor to SPE efforts since approximately 1994. Neither this table nor this paper includes a listing of the many significant contributions made in the refining of reserves definitions by numerous individuals, companies, organizations, countries, and regulatory authorities over this time period.

Users of Reserves Definitions. An effective management team of any oil- and gas-producing company must be guided in its decision-making process through access to reliable estimates of reserves and the economic value of such reserves. Most major oil companies, large independents, banks, and consultants at some point in time developed their own internal reserves definitions while acknowledging and complying with the SEC definitions since 1978. The lack of consistency and purpose in these widely differing definitions predictably led to significant problems related to project finance, mergers and acquisitions, loan portfolios, and regulatory reporting.

The 1978 SEC definitions and the 1981 SPE definitions were the catalysts initiating an almost 20-year period of efforts that have culminated in the 1997 SPE/WPC reserves definitions for proved, probable, and possible categories. These definitions have been adopted by numerous companies large and small, government agencies, and countries as the technical basis for estimating and classifying reserves worldwide, with the expressed hope that they may become the foundation for more consistent regulatory definitions over time.

Indeed, the Minerals Management Service (MMS) division of the U.S. Dept. of the Interior and the Energy Information Agency (EIA) division of the U.S. Dept. of Energy have adopted the 1997 SPE/WPC reserves definitions for their internal use and reporting. A more current and comprehensive set of petroleum reserves definitions was adopted in 2002 by the Alberta Securities Commission of Canada. While these definitions are relevant to the technology of today, they have not received much attention outside of North America and are not incorporated into the following discussion.

Similarities of SEC and SPE/WPC Proved Reserves Definitions. The following quotation is from the lead paragraph of the SEC definitions:

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. 1

The lead paragraph from the 1997 SPE/WPC definitions for proved reserves (calculated deterministically) follows:

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions.
TABLE 1—DEVELOPMENT OF PETROLEUM RESERVES DEFINITIONS

<table>
<thead>
<tr>
<th>Time Period</th>
<th>Organization Name</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1936–1964</td>
<td>API</td>
<td>Created definitions used in annual studies of oil reserves in the U.S.</td>
</tr>
<tr>
<td>1946</td>
<td>AGA</td>
<td>Established definitions for natural gas reserves and joined API in annual oil and gas reserves study for the U.S.</td>
</tr>
<tr>
<td>1964</td>
<td>SPE</td>
<td>Adopted proved reserves definitions similar to modified API definitions.</td>
</tr>
<tr>
<td>1978</td>
<td>SEC</td>
<td>Issued definitions for proved reserves of oil and gas.</td>
</tr>
<tr>
<td>1981</td>
<td>SPE</td>
<td>Issued revised definitions for proved reserves.</td>
</tr>
<tr>
<td>1983</td>
<td>WPC</td>
<td>Adopted expanded definitions for reserves and resources.</td>
</tr>
<tr>
<td>1987</td>
<td>SPE</td>
<td>Published revised definitions for proved, probable, and possible reserves. No recognition of probabilistic assessment methods.</td>
</tr>
<tr>
<td>1987</td>
<td>WPC</td>
<td>Published revised definitions somewhat similar to the 1987 SPE definitions.</td>
</tr>
<tr>
<td>1997</td>
<td>SPE/WPC</td>
<td>Definitions adopted by both SPE and WPC. Incorporated both deterministic and probabilistic methodologies.</td>
</tr>
<tr>
<td>2000</td>
<td>SPE/WPC/AAPG³</td>
<td>Resource definitions approved by SPE, WPC, and AAPG.</td>
</tr>
</tbody>
</table>


Proved reserves can be categorized as developed or undeveloped.²

Many similar phrases and terms clearly are common to both definitions, and one could conclude that reserves estimated with either definition would not differ significantly. Indeed, several areas of common agreement are described in a following section of this paper. However, the primary purpose of this paper is to concentrate attention on the differences and to provide some measure of the significance of these seemingly subtle but often important divergences in interpretation.

Terms Common to Both Definitions. Reasonable certainty is a term that is technically offensive to mathematicians and many engineers in that no clear meaning or measure of uncertainty is specified. The term has been in continuous use by SPE in reserves definitions since 1964, when it replaced an even more onerous term, “beyond reasonable doubt.” Reasonable certainty has survived for almost 40 years and is still the controlling term used in classifying proved reserves estimated with the traditional deterministic methodology.

What does the term mean? The 1997 SPE/WPC definitions attempted to bring clarity to this issue by selecting the P90 (at least a 90% chance of being exceeded) level for describing proved reserves estimated through the use of probabilistic assessment methodology. Does this then equate “reasonable certainty” to P90?

The short and long answer is “no,” and this remains one of the most vexing problems in the estimation, use, understanding, and reporting of proved reserves of oil and gas.

Commerciality is a condition expressed or implied in both definitions, but without any guidance on how commerciality is defined. The practice of the SEC has been to accept reserves estimates with net positive cash flow regardless of the magnitude of the cash flow amount or implied rate of return. The SEC does expect, however, that the reporting company will follow through with the necessary actions to ensure timely production of the reported reserves. Most other users of reserves estimates typically impose some commerciality standards, often a minimum rate of return at a level somewhat beyond simply positive cash flow.

Current economic and operating conditions are rigorously interpreted by the SEC as meaning prices and costs as of the specific date of the estimate, even though operating costs are to reflect average costs proximate to the effective report date. This verbiage is similar to language in the SPE/WPC definitions but different in that the SPE terminology is usually interpreted to allow a significantly longer period of time for determining appropriate average prices and costs.

Significant Differences in SEC and SPE/WPC Reserves Definitions. Deterministic vs. Probabilistic Methodologies. SPE has issued the P90 level guideline as appropriate for probabilistically derived proved reserves. The SEC staff has publicly stated that it will accept proved reserves with probabilistic estimates if they are done “properly.” Unfortunately, the SEC definitions and staff accounting bulletins do not define the probability level associated with proved reserves. The SEC has made it clear that none of the guidelines in place for a deterministic assessment should be ignored when probabilistic assessments are used. Although the industry has not been precluded by the SEC from using confidence levels below P90, the SPE guideline has created skepticism that lower confidence levels will be accepted by the SEC as compliant. It is fair to say that P90 is a higher standard than most filing companies are willing to accept, particularly because of the other SEC regulations that remain in effect when probabilistic methods are used.³

Determination of Lowest-Known Hydrocarbons (LKH) and Highest-Known Hydrocarbons (HKH). Although the SPE and SEC definitions may read very similarly, the SEC staff has taken a very strict position on what it will allow as the basis for the determination of LKH and HKH.

Regarding LKH, the SEC definitions state that “in the absence of information on fluid contacts, the lowest-known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.” The SEC staff has recently upheld that “known” refers to indications by log or testing and has reaffirmed that the inclusion of volumes below lowest known is prohibited. The SEC staff recognizes, however, that subsequent reservoir performance information may lead to an acceptable revision in the location of an estimated contact.

The SPE definitions state that “the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering, or performance data.” One example of what industry practitioners in some cases consider a definitive method of determining LKHS is pressure-gradient data derived from multiple formation-pressure tests using Repeat Formation Tester (RFT)⁴ or Modular Formation Dynamics Tester (MDT)⁴ tools. This information often defines the hydrocarbon contact structurally lower than the log-based LKH. The SPE definitions allow for the use of pressure data to extrapolate contacts downdip in cases in which the information is definitive. The SEC

³ Mark of Schlumberger.
staff, between 2000 and 2003, indicated that in some instances this may be acceptable in SEC filings as well, but a recent press release by a large Houston-based independent producer revealed that it was removing some proved reserves projected below log-based LKH at the request of the SEC.

For example, in Fig. 1, Well A and Well B are shown in a cross-sectional view of a sandstone reservoir. Well A penetrated the sandstone structurally high and encountered oil-bearing sand. Well B penetrated the reservoir low on structure and encountered 100% water saturation from the top to the base of the sand. The two wells are in pressure communication, and formation pressures are sampled at multiple points across each sandface in both wells A and B.

Fig. 2 shows that when the MDT pressure data are plotted as a function of depth, the oil-gradient line in Well A and the water-gradient line in Well B will intersect at the oil/water contact (OWC).

Fig. 3 shows the reservoir structure map with the SEC proved area limited by the OWC at 8,410 ft true vertical depth subsea (TVDSS) and the SPE proved area limited by the OWC at 8,500 ft TVDSS. The bulk rock volume and reserves subject to the SPE definitions are double those allowed by the SEC definitions in this example. Such large increases may be atypical, but differences of 30% or more are not uncommon.

A seismic amplitude or so called “flat spot” may confirm the calculated OWC, but even that additional data may not be enough to satisfy SEC reporting requirements.

Another problem is the possibility of a gas cap above the well penetration. This could significantly reduce the stock-tank oil originally in place (STOIP) estimate. Assume that Well A in Fig. 3 is farther away from the fault; the SEC staff is likely to ask the registrant what evidence shows that it is appropriate to fill the reservoir with oil and not gas. The SEC is likely to ask for the removal of volumes above log-based highest-known oil (HKO) unless reasonable certainty of oil to the top of structure is demonstrated with oil pressure/volume/temperature (PVT) data, indicating that the oil-saturation pressure is lower than the reservoir pressure at the top of the structure. Although the registrant may reference seismic as supporting data, the SEC is unlikely to accept oil volumes above log-based HKO as being proved without supporting PVT data and reservoir-pressure measurements.

Enhanced Oil Recovery—Use of Analogs. Both definitions permit the evaluator to rely upon the use of appropriate analogs as the basis of assigning proved reserves to a reservoir. The SPE/WPC guidelines provide little direct guidance in this regard but leave the decision to the evaluator. The SEC has, through its public presentations and its website, provided additional clarification regarding this topic. It generally defines an analog as being a similar reservoir (age, depth, lithology), preferably in the same geologic basin, that has been developed successfully as an enhanced-oil-recovery project or as one that has been designated a success through analysis of an installed pilot operation. To qualify as a candidate for having proved enhanced-recovery reserves, the subject reservoir must have the following characteristics: (1) fluid and rock properties at least equal to or more favorable than those of the successful analog, (2) a commitment by an operator to move forward with a development plan, and (3) no regulatory or legal impediments that reasonably could be expected to create a significant delay or project cancellation.

Requirement for a Conclusive Formation Test. The following two statements were taken from the SEC and the SPE/WPC definitions, respectively:

SEC—Reserves are considered proved if economic producibility is supported by either actual production or a conclusive formation test.

SPE/WPC—In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests.

Both organizations recognize that the “formation test” requirement may be relaxed in light of other proved “analog” reservoirs in the same field (SEC) or area (SPE/WPC).

In October 2002, the SEC sent letters to all registrants operating in the U.S. Gulf of Mexico (GOM) asking if proved reserves had been booked without a production flow test in a discovery situation. This action alerted the industry to the possibility that, in certain instances, the SEC may disallow the reporting of proved...
reserves without a production flow test to surface. The SEC’s inquiries sparked an industrywide discussion on what constitutes a “conclusive formation test” in light of today’s technology and operating practices, particularly in the deepwater portions of the GOM. Any competent evaluator would want to have the benefit of a 24- to 72-hour conventional formation-to-surface flow test to confirm or support economic productivity when it is feasible and necessary. Many producers have used supporting subsurface information in some defined geographical areas, such as the GOM, as the basis for economic decisions without authenticating their flow calculations through actual flow tests. This practice is acceptable under the SPE/WPC definitions and defers to the judgment of the evaluator.

These producer-made economic decisions are usually based on calculated flow rates (Darcy’s law calculations) using rock and fluid properties obtained from core and numerous pressure and fluid samples. These same flow calculations are often related to actual flow rates established in nearby analog reservoirs and fields. The quality and quantity of rock and fluid data obtainable now far exceed that available (or perhaps even foreseen) in 1978, when the SEC requirements became law.

The reasons most often cited by producers for not conducting formation-to-surface flow tests in the deepwater GOM are (1) a redundancy to calculated test rates; (2) costs, which are in the tens of millions of dollars in some cases; (3) delays of up to 2 years in planning and testing; and (4) environmental concerns and permitting requirements.

On 15 April 2004, the Corporate Finance Div. of the SEC issued a press release\(^6\) that essentially stated that it “would not object” to the booking of proved undeveloped reserves in the deepwater GOM if all the results from all openhole logs, core samples, wireline samples, and seismic surveys fully support the registrant’s conclusions. The SEC made the specific point that this applies only to reserves in the deepwater GOM and no other location. The SEC rationalized the narrow geographic application of their finding on the basis of “certain cost and environmental considerations that are particular to that geographic location and make the cost of traditional flow tests prohibitive.” The SEC’s conclusion that physical flow tests are required for new field discoveries outside the U.S. GOM may impact integrated oil companies only minimally, but the smaller independent producers with deepwater assets outside the U.S. GOM may be required to underreport certain reserves to their shareholders and potential investors. One can reasonably argue that, under these conditions, the SEC’s mandate of full disclosure is not being met.

**Revenue From Sale of Nonhydrocarbons.** No limitations are placed on evaluators using SPE/WPC definitions regarding projections of revenues generated by or created through the sale of products produced through an oil and gas field operation as long as the appropriate costs are properly included. The SEC, however, has recently confirmed its stance that only revenues produced through the sale of hydrocarbons can be reported in the calculation of future net income, both undiscounted and discounted at 10%. This, by definition, excludes revenues from the sale of sulphur, carbon dioxide, or helium, or revenues generated through the use by others of platform facilities or water-disposal systems, as examples. Such nonhydrocarbon revenues are also excluded from being used as an offset to or a reduction in operating costs by the SEC regulations. Again, this position is defended by the SEC as being a part of the standardized reporting required of all registrants.

**Reliance Upon Reservoir Simulation.** Both the SEC and SPE definitions will allow proved reserves to be estimated through the use of simulation models as long as the models meet the criteria as set out by the respective reserves definitions. Typically, the industry has constructed reservoir models with priority given to building a representative model of the reservoir, with no particular allegiance to the rules of various regulatory bodies. Traditionally, the industry has viewed the primary purpose of the simulation model as improving the understanding of the reservoir to make better business decisions regarding its development and management. The SEC staff engineers recognize that often, these models represent most-likely cases or proved plus probable reserve cases, and they perceive the need to adapt simulation models for the purpose of reporting proved reserves. How to perform this adaptation is beyond the scope of this paper, and at least one excellent SPE paper\(^7\) has already been written on the subject.

The SEC and SPE definitions are similar in their expressed and implied requirements for reliance upon reservoir simulation. The SEC has formally stated that there must be a “good history match” to rely upon simulation models for proved reserves estimation, and this should be consistent with the SPE definitional requirement of achieving “reasonable certainty.” It is our opinion that any model used, regardless of regulatory body, should have a reliable history match that validates the predictability or usefulness of the model. The question of what dictates a good history match is beyond the scope of this paper and is likely to be a topic for continued discussion. The differences between the two definitions as they relate to reservoir simulation will be present to the extent that the SEC has provided specific guidance on matters such as how to define LKH or requirements for a flow test to surface to book proved reserves. The SEC guidance, insofar as it differs from the SPE guideline of reasonable certainty, may require the use of different parameters in the construction of the model and thereby may potentially affect the model-forecast results. For example, the SEC will not allow volumes in the simulation model below log-based LKH unless it becomes impossible to honor all known data and still achieve a good history match without including the additional hydrocarbons. This is in contrast with the SPE definitions, which allow volumes to be included in the model from a projected LKH based on RFT data.

**Proved Undeveloped Reserves (PUDs).** Undeveloped reserves are most often those quantities associated with the drilling of new wells on undeveloped acreage or with the reworking or deepening of an existing well in which the cost represents a major expenditure. Undeveloped reserves may also be associated with projects in which major capital costs remain to be made before commercial production can begin, as is typically the case in the early stages of an enhanced recovery project.

Both the SPE/WPC and SEC definitions refer to drilling units of undeveloped productive units or wells (SEC) or undrilled wells offsetting wells that have indications of commercial production (SPE/WPC) as examples of proved undeveloped reserves. These terms include phrases unique to North America, where established state or provincial regulatory guidelines control well spacing and where mineral ownership is diverse and some level of protection from drainage of oil and gas across lease ownership lines is desired. Outside North America, where royalty interests are usually state or country owned, well spacing is almost always a function of optimized operations, contract limitations, and marketing conditions.

The SPE/WPC definitions will permit the designation of proved undeveloped reserves to one “direct offset” or optimum spacing unit away from another proved well with the above differences in target quantity extending beyond where geological and engineering data, in the opinion of the evaluator, support these additional locations more than one spacing unit removed from an indicated commercial well. In this context, one spacing unit away from a producing well could result in four direct locations and four diagonal locations for a total of eight undeveloped locations. Any evaluator would, of course, wish to use good judgment before assigning eight such locations without regard to lithology, fluid contacts, structural position, and other pertinent factors.

The SEC has taken a more limited position by allowing the reporting of proved reserves to only direct offsets (or spacing units) to a current or former commercial well, again only when supported by favorable engineering and geological data. Locations beyond one location away from a commercial well may be deemed proved only if they can be assured to the level of “certainty that there is continuity of production from the existing productive formation.” The SEC website release\(^8\) on 30 June 2000 further explains that “there is no mitigating modifier for the word certainty.” Although many reserves evaluators believe that the level of confidence intended was that afforded by the overriding phrase “reasonable certainty,” the word certainty remains in its unmodified form in the SEC definitions regarding proved undeveloped reserves.
Given a circumstance in which a well-defined structure with extraordinary evidence of reservoir quality and continuity and established fluid contacts exists, interior well locations (more than one spacing unit away from a commercial well) between widely spaced commercial wells can be reported to the SEC as proved locations only if reservoir continuity can be definitively supported by pressure-interference tests between those widely spaced existing wellbores. **Coalbed Methane (CBM) Reserves.** Natural gas reserves from underground coal seams have become a significant part of the U.S. gas supply and are a growing source of gas worldwide. Neither the SEC nor the SPE/WPC definitions specifically refer to any special rules or regulations affecting the classification or quantification of proved CBM reserves, even though CBM is adsorbed into the coal and does not reside in the porosity of sedimentary rocks, as is commonplace for traditional oil and natural gas. All the standardized requirements regarding flow testing, downhole limits, and other limitations regarding proved traditional oil and gas reserves apply to CBM reserves.

Regarding CBM PUDs, the SEC position on undrilled locations more than one spacing unit away from a commercial well remains the same in that the mere assurance of the presence of a coal seam at those undrilled locations does not meet the SEC standard for certainty of the continuity of production. In many CBM projects, deeper drilling for oil and gas has clearly established the presence and thickness of coal seams throughout the area. Without adequate testing, however, to confirm adequate permeability in undrilled areas beyond the allowed one-location stepouts from commercial CBM completions, no proved undeveloped reserves can be assigned to these “second-tier” locations under the current SEC interpretation of its definitions.

Under the SPE/WPC definitions, the evaluator is not restricted to this limitation and may exercise his judgment in view of the quality and quantity of all available data. **Assured Markets and Contracts for the Sale of Oil and/or Gas.** The SEC definitions do not specifically address the requirement for an established market for oil and gas, but the existence of such is clearly implied in its reference to “existing economic and operating conditions.” The SPE/WPC definitions similarly refer to “current economic conditions” as well as the requirement for facilities to transport “those reserves to market.” The “reasonable certainty” mandate that overrides all deterministic estimates of proved reserves would further seem to argue for a high level of assurance for an opportunity to sell produced oil and/or gas under some defined terms related to price and product quality and quantities.

Under either set of definitions for proved reserves, the evaluator must have adequate data to (1) confirm that a market for produced hydrocarbons exists or will come into existence at a certainty that any required sales contracts are sufficiently advanced to provide reasonable assurance of sales quantities and prices, and (3) that all necessary facilities are in place or adequate confirmations have been received to ensure the timely installation and operation of these required facilities. Each of these requirements must be investigated in sufficient depth to ascertain the reliability of representations made. Must all enabling contracts be in place? Ideally so, but there may be circumstances in which a memorandum of understanding may be sufficiently advanced to define all the relevant commercial terms of a sales contract and may be deemed adequate proof of a firm commitment. There is no “cookbook” of terms that will always be applicable and used in this determination. Instead, the judgment, experience, and integrity of the evaluator will be the most important elements in this determination.

**Cost Allocation to Nonproved Reserves.** In practice, most producers will give consideration to both proved and probable reserves in their decision processes leading to the sanctioning of a project or in devising and approving a development plan. In so doing, certain costs may be assigned or allocated to each reserves category. One should not assume, however, that these allocated costs for the proved reserves component are appropriate for the estimation and reporting of proved reserves, either for the SEC or the SPE/WPC reserves definitions.

For example, assume that two wells have been drilled in the GOM and have confirmed a significant oil discovery. If the proved reserves associated with these two wells cannot economically support the capital expenditure required to construct a platform, drill the remaining wells, and install the required production facilities and a pipeline connection, then the reserves established by these two wells do not meet the reporting requirements as proved using SEC standards or, for that matter, SPE/WPC standards. However, if a production scheme could be devised that allows the economic production of the proved reserves established by the two wells, this may then allow for the reporting of proved reserves even though the producer may not follow this ultimate plan. This alternate production plan could take many forms but would need to meet all relevant standards.

**Inclusion of Overhead Charges in Operating Expenditures (OPEX).** Although the SPE reserves definitions are silent on whether overhead charges should be included in the OPEX, the SEC staff has recently provided clarifying guidance to the effect that indirect overhead should be included in the OPEX. The SEC staff recently has gone on record as stating that one “red flag” issue they see in their periodic review of SEC filings is inconsistencies in the total OPEX reported in the financial report of the securities filing, as compared to the OPEX used to forecast reserves. The SEC staff member reviewing the filing is likely to call into question any filing that is not fairly consistent in this regard. If the SEC position on this issue indeed requires additional OPEX to be included in the reserves evaluation, this will lower the SEC proved reserves relative to the SPE proved reserves. The severity of the difference between the SEC and the SPE reserves will increase as the economic robustness of the project diminishes.

**Use of Data Past Effective Report Date.** Significant differences in reserves can result from differences between what the SEC and SPE definitions will allow regarding the use of information past the effective date of the report. The SEC expressly forbids the inclusion of information beyond the effective date of the reserves report, but it does require that material events beyond the effective date be disclosed somewhere in the filing. The SPE definitions generally are not interpreted as strictly on this point as the SEC definitions, but if data beyond the report date are used under SPE guidelines, then a footnote or statement should be included to inform the user of that fact. Fields that are fairly immature in their development and do not have lengthy production histories are more susceptible to significant changes in their estimated proved reserves with the inclusion of a few more months of information.

**Net Profits Interest.** The SEC has at the October 2002 Soc. of Petroleum Evaluation Engineers (SPEE) Forum affirmed its position that hydrocarbon quantities attributable to a net profits interest (NPI) should be considered as reserves and therefore deducted from the leasehold ownership interests of any producer owning a working and net revenue interest in a property subject to the payment of an NPI. This is contrary to traditional industry practice and is not addressed in the SPE/WPC reserves definitions. Because there is no “standard language” common to all NPI agreements, the recommendation is made here that SEC respondents carefully read the controlling terms of each NPI agreement and comply with any ownership terms contained therein.

**Separate Reporting of Mineral Interest and Production-Sharing Contract (PSC) Reserves.** The SEC has recently taken a position that reserves captured under PSCs and master service contracts (MSCs) are distinctive and should be reported as such. The SEC staff has also recently stated publicly that PSC reserves should not be added to those obtained through direct mineral interest ownership. The requirement of separate reporting of reserves by the SEC has only recently been discussed and may be contested by some publicly traded producers. This distinction does not necessarily set up a quantifiable difference in proved reserves between the two sets of definitions, but it may invoke a perceived quality difference.

**Undrilled Fault Blocks or Structures.** Seismic-imaging technology has advanced to the point at which it may be combined with subsurface data to reliably predict successes or failures of drilling in undrilled fault blocks or nearby analogous structures in certain geological settings. Confidence factors approaching 90% or
perhaps higher often can be assigned to some locations in undrilled fault segments or structures. This may lead to the assumption that the reasonable certainty test for deterministically calculated reserves or the P90 standard for proved reserves using a probabilistic approach has been met, and proved reserves can be the result.

Despite the sensible appeal of this type of analysis, neither of the definitions will accommodate the designation this because of the common requirement for a “known accumulation” for proved reserves to be assigned.\(^9\) Common practice across the industry has been to require that a known accumulation be confirmed by drilling a well and acquiring adequate data to support the designation and quantification of proved reserves. Earth scientists may vigorously dispute the meaning of a known accumulation. Reserves engineers are prone to reduce the term to the level of a single reservoir characterized and confined by a common and unique pressure system. In contrast, geoscientists often take the larger, more global view of a field, perhaps with many reservoirs at varying depths, as a common accumulation.

**Prices To Use for Evaluating Reserves. Future Oil and Gas Prices.** Both definitions call for the use of constant future prices for oil, gas, and plant products based on current economic or operating conditions. The SPE/WPC definitions allow the evaluator some latitude in determining how this is to be established and suggest further that the use of an averaging period appropriate to the purpose of the evaluation may be used. The SEC position allows no interpretation in this regard but strictly mandates that the responding company use prices in effect on the date of the evaluation, typically 31 December. In 1978, most gas sales were made in the U.S. and elsewhere through defined-price sales contracts. Seasonal swings and other market-related price fluctuations did not take place except for certain inflation-adjusted contracts. Most crude was sold through local spot markets under periodic but irregular changes in posted prices.

Within the U.S., most gas is now sold by producers through a well-developed spot market that has continued to mature over the past 20 years. The SEC position is that the physical price for natural gas sold on 31 December is the appropriate price, even though a producer may have sold gas under a December contract at an established agreed-to-price in November. This year-end price is to be used for all purposes—that is to say, for revenue projections and for the calculation of economic limits and, therefore, reserves. Many producers may impose physical limitations on the lives of existing wellbores and facilities should the 31 December prices be so abnormally high as to result in calculated economic well lives far beyond those estimated with average or expected future prices.

**Figs. 4 and 5** illustrate the variations over the most recent 15-year period when comparing 1-day year-end prices to the trailing 12-month average prices for both oil and gas. Neither method of determining appropriate prices to be used in estimating reserves is recommended in this paper, but most evaluators are more comfortable with average prices than with any 1-day price on any date. The variations in year-end spot prices to average annual prices differ as much as a positive 33% to a negative 24% for oil and a positive 117% to a negative 35% for natural gas. The consequence of these variations in reserves estimation can be quite significant and potentially misleading to investors and others.

The SEC justifies its insistence on the use of 31 December prices by saying that this method is required for consistency among all producers in the calculation of a “standardized measure” of oil and gas values.

**PSC/MSC.** In many respects, the methods to estimate proved reserves under PSCs and MSCs using the SEC and SPE definitions are similar, but significant variations may result from the commodity prices used in the evaluations. The economic-interest method is the most widely used approach in determining net proved reserves volumes to a specific party’s interests. That method entails dividing the product price used in the evaluation into the contractor’s net revenue. The contractor’s net revenue is calculated by modeling the terms of the PSC or MSC. As previously discussed and illustrated in Figs. 4 and 5, assuming the annual average pricing is used for reporting reserves under the SEC guidelines, the differences in evaluation pricing between the SEC and SPE definitions were shown on occasion to be as much as 34% in some years, in the case of oil, and as much as 118% in the case of gas. This price difference can directly affect the net reserves to the contractor under the SEC-recommended economic-interest method of recognizing reserves. In the extreme case, the contractor’s entitlement may not be affected by the differences in product pricing, so the impact on net reserves can be directly proportional to the differences in product price.

**WTI Oil Prices**

**COMPARISON OF YEAR-END PRICE TO ANNUAL AVERAGE PRICE**

Fig. 4—Comparison of year-end WTI oil price to annual average WTI oil price (source: EIA via www.eia.doe.gov).
Contract Expiration Dates. Neither the SEC definitions nor the SPE definitions give specific guidance on whether to include reserves that are scheduled to be produced beyond contract expiration dates. However, both definitions require that reserves included in the proved category meet the test of "reasonable certainty." In most cases, extrapolating future conditions and pricing terms beyond a known expiration date will not meet this test. One exception may be in situations in which the contract permits an extension of the contractual term upon request. Another possible exception may be in cases in which an extension of the contract presents a win-win situation for both parties and the historical record of obtaining extensions with the controlling government or governing body is extremely likely and virtually assured on the basis of historical records.

Reporting Lease-Use Gas as Reserves. Both definitions permit the reporting of gas volumes as reserves and forecasting production that includes sales volumes plus volumes used, typically as fuel, on the lease or in the field. The forecast operating cost must be increased by the estimated value of the lease-use gas using the appropriate (typically 31 December) gas price as the cost of fuel gas. This replicates the equivalent purchase of fuel gas and permits the reporting of the larger volume of reserves and future production.

Conclusions
Petroleum reserves definitions are not static; they have tended to evolve over time and as practitioners have begun to communicate with others worldwide. The SPE/WPC definitions were established in 1997 with the hope and expectation that they could be used as an integral part in ongoing discussions with other organizations and entities that have a voice in the continuing debate. The use of reserves information by a regulatory agency in the U.S., a major integrated oil producer in its corporate planning, or a state-owned producer in a country where its primary wealth is in oil resources all present different circumstances and objectives.

Despite these disparate viewpoints and conditions, hope remains that regulators and others can begin to either adopt new, more modern and technically appropriate definitions on a global basis or to adapt their interpretations in light of the relevant technologies that are in everyday use in the industry and upon which major investment decisions are made daily.

References
4. Discussion comments made by SEC staff petroleum engineers during Society of Petroleum Evaluation Engineers (SPEE) -sponsored Forums to discuss SEC reserves definitions and applications, Houston, 31 October and 1 November 2000, 23 October 2001, and 22 October 2002.

SI Metric Conversion Factors

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<th>Unit</th>
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*Conversion factor is exact.

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erty evaluations for acquisitions and divestitures, financing, reservoir management, gas-supply analysis, gas-storage studies, and litigation support. He graduated magna cum laude with a BS degree in petroleum engineering from Louisiana Tech U. Harrell is also a member of SPEE. He has led the way in exploring emerging issues on reserves reporting requirements with the SEC. Harrell chaired the SPEE forum cited in this article. Thomas L. Gardner is International Vice President at Ryder Scott Co. L.P. in Houston and has evaluated international petroleum properties for 19 years. He has managed multidisciplinary evaluation teams and prepared independent studies for acquisitions and divestitures, financing, and reservoir management. He also consults on regulatory compliance in reserves reporting. He previously worked for Exxon Corp. Gardner holds a BS degree in petroleum engineering and an MBA degree, both from Texas A&M U. He is also a member and former Houston Chapter Chairman of SPEE and a part of the leadership team that organized the SPEE forum cited in this article.