Exhibit 73

OPINION OF

FORREST A. GARB & ASSOCIATES, INC.

BY W. D. HARRIS III

REGARDING

THE IMPACT OF SEC STAFF GUIDANCE

ON THE DEFINITION OF

PROVED RESERVES,

AS SET FORTH IN

SECURITIES AND EXCHANGE COMMISSION'S

PUBLISHED DEFINITIONS AND DOCUMENTS

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Forrest A. Garb & Associates, Inc. (FGA) hereby submits its report concerning the impact of certain guidance issued by the Securities and Exchange Commission's Accounting Staff Members Division of Corporation Finance (SEC Staff) as that guidance relates to the SEC's definitions of proved oil and gas reserves.

The regulation that forms the basis of the reporting of proved oil and gas reserves is contained in SEC Regulation S-X. The definitions for proved oil and gas reserves are given in § 210.4-10 of Regulation S-X (17 C.F.R. § 210.4-10), promulgated pursuant to the Federal Securities Laws and the Energy Policy and Conservation Act of 1975, and are included in this opinion as Attachment A.

Regulation S-X § 210.4-10 defines proved developed and undeveloped oil and gas reserves as:

"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. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions."

"Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved."

"Proved undeveloped oil and gas reserves are reserves 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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should 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 tests in the area and in the same reservoir."

Subsequent to the SEC's promulgation of Regulation S-X, § 210.4-10, the SEC Staff issued a release on June 30, 2000, concerning oil and gas reserve definitions and requirements. The June 2000 staff release does not change the definitions of proved reserves set forth in Regulation S-X, § 210.4-10, but rather considers those definitions in light of updated technology. The cover page of the June 2000 staff release and the relevant section, which specifically addresses oil and gas reserve definitions, are included in this opinion as Attachment B.

Another release was issued by the SEC Staff on November 14, 2000, which provides updates to the June 2000 staff release; but the definitions of proved reserves set forth in Regulation S-X, § 210.4-10, were not changed. The cover page of the November 2000 staff release and § VIII.A.16, which specifically addresses the oil and gas reserve definitions, are included in this opinion as Attachment C.

A March 31, 2001, SEC staff release entitled "Division of Corporation Finance: Frequently Requested Accounting and Financial Reporting Interpretations and Guidance" also addressed the proved oil and gas reserve definitions set forth in Regulation S-X, § 210.4-10, and is included as Attachment D. As with attachment C, this document does not change the definition of proved oil and gas reserves.

It is the responsibility of the SEC staff, including staff engineers, to assist companies with the interpretation of, and compliance with, these laws and regulations in the spirit in which they were written. It is the responsibility solely of the Commissioners to amend the reserves-reporting rules as they see fit, which may be brought to their attention by SEC engineers and other staff. This is described in the following excerpt from the SEC document, "The Investor's Advocate: How the SEC Protects Investors, Maintains Market Integrity, and Facilitates Capital Formation," under the section "Organization of the SEC," and pointed out in the highlighted portion of the passage quoted immediately below.

The Commissioners

The Securities and Exchange Commission has five Commissioners who are appointed by the President of the United States with the advice and consent of the Senate. Their terms last five years and are staggered so that one Commissioner's term ends on June 5 of each year. To ensure that the Commission remains non-partisan, no more than three Commissioners may belong to the same political party. The President also designates one of the Commissioners as Chairman, the SEC's top executive.

The Commissioners meet to discuss and resolve a variety of issues the staff brings to their attention. At these meetings the Commissioners:

- interpret federal securities laws;
- amend existing rules;
- propose new rules to address changing market conditions; and/or
- enforce rules and laws.

These meetings are open to the public and the news media unless the discussion pertains to confidential subjects, such as whether to begin an enforcement investigation.[1]

[1] This document can be found at the following URL on the SEC website: http://www.sec.gov/about/whatwedo.shtml.

Thus, only the SEC commissioners, not the SEC Staff, can alter the definition of proved reserves, as set forth in Regulation S-X, § 210.4-10. The commissioners, however, have never done so.

In my opinion, the SEC's definition of proved reserves has remained the same since Regulation S-X, § 210.4-10 was passed in 1978. The releases of the SEC Staff, discussed above, merely provided guidance as to how to comply with Regulation S-X, § 210.4-10.

Included as attachments to this report are my resume (Attachment E), list of publications (Attachment F), compensation (Attachment G), and the list of expert witness/depositions given over the preceding four years (Attachment H).

FGA is an independent firm of geologists and petroleum engineers. Neither the firm nor its employees own any interest in the properties in question, nor have we been employed on a contingency basis.

This report was prepared by and under the supervision of W.D. Harris III, Registered Professional Engineer No. 75222, State of Texas.

W. D. Harris III

W. D. Harris III
Chief Executive Officer
Forrest A. Garb & Associates, Inc.

FORREST A. GARB & ASSOCIATES, INC.

ATTACHMENTS

A. REGULATION S-X SECTION 210.4-10, DEFINITIONS FOR OIL AND GAS RESERVES

B. EXCERPT FROM SECURITIES AND EXHANGE COMMISSION DOCUMENT "CURRENT ACCOUNTING AND DISCLOSURE ISSUES", JUNE 30, 2000

C. EXCERPT FROM SECURITIES AND EXHANGE COMMISSION DOCUMENT "CURRENT ISSUES AND RULEMAKING PROJECTS", NOVEMBER 14, 2000

D. EXCERPT FROM SECURITIES AND EXHANGE COMMISSION DOCUMENT "FREQUENTLY REQUESTED ACCOUNTING AND FINANCIAL REPORTING INTERPRETATIONS AND GUIDANCE", MARCH 31, 2001

E. RESUME OF MR. WILLIAM D. HARRIS, III

F. PUBLICATIONS OF MR. WILLIAM D. HARRIS, III

G. COMPENSATION OF MR. WILLIAM D. HARRIS, III

H. HISTORY OF EXPERT TESTIMONY AND DEPOSITION OF MR. WILLIAM D. HARRIS III WITHIN THE PRECEDING FOUR YEARS

ATTACHMENT A

REGULATION S-X SECTION 210.4-10, DEFINITIONS FOR OIL AND GAS RESERVES

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

Reg. § 210.4-10.

This section prescribes financial accounting and reporting standards for registrants with the Commission engaged in oil and gas producing activities in filings under the federal securities laws and for the preparation of accounts by persons engaged, in whole or in part, in the production of crude oil or natural gas in the United States, pursuant to Section 503 of the Energy Policy and Conservation Act of 1975 [42 U.S.C. 6383] ("EPCA") and section 11(c) of the Energy Supply and Environmental Coordination Act of 1974 [IS U.S.C. 796] ("ESECA"), as amended by section 505 of EPCA. The application of this section to those oil and gas producing operations of companies regulated for rate-making purposes on an individual-company-cost-of-service basis may, however, give appropriate recognition to differences arising because of the effect of the rate-making process.

Exemption. Any person exempted by the Department of Energy from any record-keeping or reporting requirements pursuant to Section 11(c) of ESECA, as amended, is similarly exempted from the related provisions of this section in the preparation of accounts pursuant to EPCA. This exemption does not affect the applicability of this section to filings pursuant to the federal securities laws.

Definitions

(a) *Definitions.* The following definitions apply to the terms listed below as they are used in this section:

(1) *Oil and gas producing activities.*

(i) Such 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 and/or for the purpose of removing the oil or gas from existing reservoirs on those properties.

(C) The construction, drilling and production activities necessary to retrieve oil and gas from its natural reservoirs, and the acquisition, construction, installation, and maintenance of field gathering and storage systems — including lifting the oil and gas to the surface and gathering, treating, field processing (as in the case of processing gas to extract liquid hydrocarbons) and field storage. For purposes of this section, the oil and gas production function shall normally be regarded as terminating at the outlet valve on the lease or field storage tank; if unusual physical or operational circumstances exist, it may be appropriate to regard the production functions as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal.

(ii) Oil and gas producing activities do not include:

(A) The transporting, refining and marketing of oil and gas.

(B) Activities relating to the production of natural resources other than oil and gas.

(C) The production of geothermal steam or the extraction of hydrocarbons as a by-product of the production of geothermal steam or associated geothermal resources as defined in the Geothermal Steam Act of 1970.

(D) The extraction of hydrocarbons from shale, tar sands, or coal.

(2) *Proved oil and gas reserves.* 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. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";

(B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

(3) *Proved developed oil and gas reserves.* Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot

project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

(4) *Proved undeveloped reserves.* Proved undeveloped oil and gas reserves are reserves 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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should 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 Leave been proved effective by actual tests in the area and in the same reservoir.

(5) *Proved properties.* Properties with proved reserves.

(6) *Unproved properties.* Properties with no proved reserves.

(7) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

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

(9) *Reservoir.* 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.

(10) *Exploratory well.* A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well as those items are defined below.

(11) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known-to be productive.

(12) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of 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.

(13) *Stratigraphic test well.* A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily arc drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) "exploratory type," if not drilled in a proved area, or (ii) "development type," if drilled in a proved area.

(14) *Acquisition of properties.* 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, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(15) *Exploration costs.* 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.

(16) *Development costs.* 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 well 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 test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the 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.

(17) *Production costs.*

(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.

Successful Efforts Method

(b) A reporting entity that follows the successful efforts method shall comply with the accounting and financial reporting disclosure requirements of Statement of Financial Accounting Standards No. 19, as amended.

Full Cost Method

(c) *Application of the full cost method of accounting.* A reporting entity that follows the full cost method shall apply that method to all of its operations and to the operations of its subsidiaries, as follows:

(1) *Determination of cost centers.* Cost centers shall be established-on a country-by-country basis.

(2) Costs to be capitalized. All costs associated with property acquisition, exploration, and development activities (as defined in paragraph (a) of this section) shall be capitalized within the appropriate cost center. Any internal costs that are capitalized shall be limited to those costs that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account, and shall not include any costs related to production, general corporate overhead, or similar activities.

(3) *Amortization of capitalized costs.* Capitalized costs within a cost center shall be amortized on the unit-of-production basis using proved oil and gas reserves, as follows:

(i) Costs to be amortized shall include (A) all capitalized costs, less accumulated amortization, other than the cost of properties described in paragraph (ii) below; (B) the estimated future expenditures (based on current costs) to be incurred in developing proved reserves; and (C) estimated dismantlement and abandonment costs, net of estimated salvage values.

(ii) The cost of investments in unproved properties and major development projects may be excluded from capitalized costs to be amortized, subject to the following:

(A) All costs directly associated with the acquisition and evaluation of unproved properties may be excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties, subject to the following conditions: (1) Until such a determination is made, the properties shall be assessed at least annually to ascertain whether impairment has occurred. Unevaluated properties whose costs are individually significant shall be assessed individually. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties may be grouped for purposes of assessing impairment. Impairment may be estimated by applying factors based on historical experience and other data such as primary Lease terms of the properties, average holding periods of unproved properties, and geographic and geologic data to groupings of individually insignificant properties and projects. The amount of impairment assessed under either of these methods shall be added to the costs to be amortized. (2) The costs of drilling exploratory dry holes shall be included in the amortization base immediately upon determination that the well is dry. (3) If geological and geophysical costs cannot be directly associated with specific unevaluated properties, they shall be included in the amortization base as incurred. Upon complete evaluation of a property, the total remaining excluded cost (net of any impairment) shall be included in the full cost amortization base.

(B) Certain costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore drilling platform from which development wells are to be drilled, the installation of improved recovery programs, and similar major projects undertaken in the expectation of Significant additions to proved reserves). The amounts which may be excluded are applicable portions of (1) the costs that relate to the major development project and have not previously been included in the amortization base, and (2) the estimated future expenditures associated with the development project. The excluded portion of any common costs associated with the development project should be based, as is most appropriate in the circumstances, on a comparison of either (i) existing proved reserves to total proved reserves expected to be established upon completion of the project, or (ii) the number of wells to which proved reserves have been assigned and total number of wells expected to be drilled. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.

(C) Excluded costs and the proved reserves related to such costs shall be transferred into the amortization base on an ongoing (well-by-well or property-by-property) basis as the project is evaluated and proved reserves established or impairment determined. Once proved reserves are established, there is no further justification for continued exclusion from the full cost amortization base even if other factors prevent immediate production or marketing.

(iii) Amortization shall be computed on the basis of physical units, with oil and gas converted to a common unit of measure on the basis of their approximate relative energy content, unless economic circumstances (related to the effects of regulated prices) indicate that use of units of revenue is a more appropriate basis of computing amortization. In the latter case, amortization shall be computed on the basis of current gross revenues (excluding royalty payments and net profits disbursements) from production in relation to future cross revenues, based on current prices (including consideration of changes in existing prices provided only by contractual arrangements), from estimated production of proved oil and gas reserves. The effect of a significant price increase during the year on estimated future gross revenues shall be reflected in the amortization provision only for the period after the price increase occurs.

(iv) In some cases it may be more appropriate to depreciate natural gas cycling and processing plants by a method other than the unit-of-production method.

(v) Amortization computations shall be made on a consolidated basis, including investees accounted for on a proportionate consolidation basis. Investees accounted for on the equity method shall be treated separately.

(4) *Limitation on capitalized costs:*

(i) For each cost center, capitalized costs, less accumulated amortization and related deferred income taxes, shall not exceed an amount (the cost center ceiling) equal to the sum of:

(A) the present value of estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of ten percent and assuming continuation of existing economic conditions; plus

(B) the cost of properties not being amortized pursuant to paragraph (i)(3)(ii) of this section; plus

(C) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; less

(D) income tax effects related to differences between the book and tax basis of the properties referred to in paragraphs (i)(4)(i)(B) and (C) of this section.

(ii) If unamortized costs capitalized within a cost center, less related deferred income taxes, exceed the cost center ceiling, the excess shall be charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off shall not be reinstated for any subsequent increase in the cost center ceiling.

(5) *Production costs.* All costs relating to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, shall be charged to expense as incurred.

(6) *Other transactions.* The provisions of paragraph (h) of this section, "Mineral property conveyances and related transactions if the successful efforts method of accounting is followed," shall apply also to those reporting entities following the full cost method except as follows:

(i) *Sales and abandonments of oil and gas properties.* Sales of oil and gas properties, whether or not being amortized currently, shall be accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. For instance, a significant alteration would not ordinarily be expected to occur for sales involving less than 25 percent of the reserve quantities of a given cost center. If gain or loss is recognized on such a sale, total capitalization costs within the cost center shall be allocated between the reserves sold and reserves retained on the same basis used to compute amortization, unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs shall be allocated on the basis of the relative fair values of the properties. Abandonments of oil and gas properties shall be accounted for as adjustments of capitalized costs; that is, the cost of abandoned properties shall be charged to the full cost center and amortized (subject to the limitation on capitalized costs in paragraph (b) of this section).

(ii) *Purchases of reserves.* Purchases of oil and gas reserves in place ordinarily shall be accounted for as additional capitalized costs within the applicable cost center; however, significant purchases of production payments or properties with lives substantially shorter than the composite productive life of the cost center shall be accounted for separately.

(iii) *Partnerships, joint ventures and drilling arrangements.*

(A) Except as provided in subparagraph (i)(6)(i) of this section, all consideration received from sales or transfers of properties in connection with partnerships, joint venture operations, or various other forms of drilling arrangements involving oil and gas exploration and development activities (e.g., carried interest, turnkey wells, management fees, etc.) shall be credited to the full cost account, except to the extent of amounts that represent reimbursement of organization, offering, general and administrative expenses, etc., that are identifiable with the transaction, if such amounts are currently incurred and charged to expense.

(B) Where a registrant organizes and manages a limited partnership involved only in the purchase of proved developed properties and subsequent distribution of income from such properties, management fee income may be recognized provided the properties involved do not require aggregate development expenditures in connection with production of existing proved reserves in excess of 10% of the partnership's recorded cost of such properties. Any income not recognized as a result of this limitation would be credited to the full cost account and recognized through a lower amortization provision as reserves are produced.

(iv) *Other services*. No income shall be recognized in connection with contractual services performed (e.g. drilling, well service, or equipment supply services, etc.) in connection with properties in which the registrant or an affiliate (as defined in § 210.1-02(b)) holds an ownership or other economic interest, except as follows:

(A) Where the registrant acquires an interest in the properties in connection with the service contract, income may be recognized to the extent the cash consideration received exceeds the related contract costs plus the registrant's share of costs incurred and estimated to be incurred in connection with the properties. Ownership interests acquired within one year of the date of such a contract are considered to be acquired in connection with the service for purposes of applying this rule. The amount of any guarantees or similar arrangements undertaken as part of this contract should be considered as part of the costs related to the properties for purposes of applying this rule.

(B) Where the registrant acquired an interest in the properties at least one year before the date of the service contract through transactions unrelated to the service contract, and that interest is unaffected by the service contract, income from such contract may be recognized subject to the general provisions for elimination of intercompany profit under generally accepted accounting principles.

(C) Notwithstanding the provisions of (A) and (B) above, no income may be recognized for contractual services performed on behalf of investors in oil and gas producing activities managed by the registrant or an affiliate. Furthermore, no income may be recognized for contractual services to the extent that the consideration received for such services represents an interest in the underlying property.

(D)Any income not recognized as a result of these rules would be credited to the full cost account and recognized through a lower amortization provision as reserves are produced.

(7) *Disclosures*. Reporting entities that follow the full cost method of accounting shall disclose all of the information required by paragraph (k) of this section, with each cost center considered as a separate geographic area, except that reasonable groupings may be made of cost centers that are not significant in the aggregate. In addition:

(i) For each cost center for each year that an income statement is required, disclose the total amount of amortization expense (per equivalent physical unit of production if amortization is computed on the basis of physical units or per dollar of gross revenue from production if amortization is computed on the basis of gross revenue).

(ii) State separately on the face of the balance sheet the aggregate of the capitalized costs of unproved properties and major development projects that are excluded, in accordance with paragraph (i)(3) of this section, from the capitalized costs being amortized. Provide a description in the notes to the financial statements of the current status of the significant properties or projects involved, including the anticipated timing of the inclusion of the costs in the amortization computation. Present a table that shows, by category of cost, (A) the total costs excluded as of the most recent fiscal year; and (B) the amounts of such excluded costs, incurred (1) in each of the three most recent fiscal years and (2) in the aggregate for any earlier fiscal years in which the costs were incurred. Categories of cost to be disclosed include acquisition costs, exploration costs, development costs in the case of significant development projects and capitalized interest.

Income taxes

(d) *Income taxes.* Comprehensive interperiod income tax allocation by a method which complies with generally accepted accounting principles shall be followed for intangible drilling and development costs and other costs incurred that enter into the determination of taxable income and pretax accounting income in different periods.

ATTACHMENT B

EXCERPT FROM
SECURITIES AND EXHANGE COMMISSION DOCUMENT
"CURRENT ACCOUNTING AND DISCLOSURE ISSUES",
JUNE 30, 2000

Division of Corporation Finance: Current Accounting and Disclosure Issues

June 30, 2000

Prepared by Accounting Staff Members in the Division of Corporation Finance
U.S. Securities and Exchange Commission
Washington, D.C.

Contents

Issues in the Extractive Industry

Mining Exploration Costs

Recoverability of capitalized costs is likely to be insupportable under FASB Statement No. 121 prior to determining the existence of a commercially minable deposit, as contemplated by Industry Guide 7 for a mining company in the exploration stage. As a result, the staff would generally challenge capitalization of exploration costs, and believes that those costs should be expensed as incurred during the exploration stage under US GAAP.

Definition of Proved Reserves

Over the last several years, the estimation and classification of petroleum reserves has been impacted by the development of new technologies such as 3-D seismic interpretation and reservoir simulation. Computer processor improvements have allowed the increased use of probabilistic methods in proved reserve assessments. These have led to issues of consistency and, therefore, some confusion in the reporting of proved oil and gas reserves by public issuers in their filings with the Commission. This section discusses some issues the Division of Corporation Finance's engineering staff has identified in its review of such filings.

The definitions for proved oil and gas reserves for the SEC are found in Rule 4-10(a) of Regulation S-X of the Securities Exchange Act of 1934. The SEC definitions are below in bold italics. Under each section we have tried to explain the SEC staff's position regarding some of the more common issues that arise from each portion of the definitions. As most engineers who deal with the classification of reserves have come to realize, it is difficult, if not impossible, to write reserve definitions that easily cover all possible situations. Each case has to be studied as to its own unique issues. This is true with the Society of Petroleum Engineers' and others' reserve definitions as well as the SEC's definitions.

1. 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. Prices include consideration of changes in existing prices provided by contractual arrangements, but not on escalations based upon future conditions.

The determination of reasonable certainty is generated by supporting geological and engineering data. There must be data available which indicate that assumptions such as decline rates, recovery factors, reservoir limits, recovery mechanisms and volumetric estimates, gas-oil ratios or liquid yield are valid. If the area in question is new to exploration and there is little supporting data for decline rates, recovery factors, reservoir drive mechanisms etc., a conservative approach is appropriate until there is enough supporting data to justify the use of more liberal parameters for the estimation of proved reserves. The concept of reasonable certainty implies that, as more technical data becomes available, a positive, or upward, revision is much more likely than a negative, or downward, revision.

Existing economic and operating conditions are the product prices, operating costs, production methods, recovery techniques, transportation and marketing arrangements, ownership and/or entitlement terms and regulatory requirements that are extant on the effective date of the estimate. An anticipated change in conditions must have reasonable certainty of occurrence; the corresponding investment and operating expense to make that change must be included in the economic feasibility at the appropriate time. These conditions include estimated net abandonment costs to be incurred and duration of current licenses and permits.

If oil and gas prices are so low that production is actually shut-in because of uneconomic conditions, the reserves attributed to the shut-in properties can no longer be classified as proved and must be subtracted from the proved reserve data base as a negative revision. Those volumes may be included as positive revisions to a subsequent year's proved reserves only upon their return to economic status.

2. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limits of the reservoir.

Proved reserves may be attributed to a prospective zone if a conclusive formation test has been performed or if there is production from the zone at economic rates. It is clear to the SEC staff that wireline recovery of small volumes (e.g. 100 cc) or production of a few hundred barrels per day in remote locations is not necessarily conclusive. Analyses of open-hole well logs which imply that an interval is productive are not sufficient for attribution of proved reserves. If there is an indication of economic producibility by either formation test or production, the reserves in the legal and technically justified drainage area around the well projected down to a known fluid contact or the lowest known hydrocarbons, or LKH may be considered to be proved.

In order to attribute proved reserves to legal locations adjacent to such a well (i.e. offsets), there must be conclusive, unambiguous technical data which supports reasonable certainty of production of such volumes and sufficient legal acreage to economically justify the development without going below the shallower of the fluid contact or the LKH. In the absence of a fluid contact, no offsetting reservoir volume below the LKH from a well penetration shall be classified as proved.

Upon obtaining performance history sufficient to reasonably conclude that more reserves will be recovered than those estimated volumetrically down to LKH, positive reserve revisions should be made.

3. Reserves which can be produced economically through applications of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

If an improved recovery technique which has not been verified by routine commercial use in the area is to be applied, the hydrocarbon volumes estimated to be recoverable cannot be classified as proved reserves unless the technique has been demonstrated to be technically and economically successful by a pilot project or installed program in that specific rock volume. Such demonstration should validate the feasibility study leading to the project.

4. Estimates of proved reserves do not include the following:

- oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";
- crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
- crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects;
- crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other sources.

Geologic and reservoir characteristic uncertainties such as those relating to permeability, reservoir continuity, sealing nature of faults, structure and other unknown characteristics may prevent reserves from being classified as proved. Economic uncertainties such as the lack of a market (e.g. stranded hydrocarbons), uneconomic prices and marginal reserves that do not show a positive cash flow can also prevent reserves from being classified as proved. Hydrocarbons "manufactured" through extensive treatment of gilsonite, coal and oil shales are mining activities reportable under Industry Guide 7. They cannot be called proved oil and gas reserves. However, coal bed methane gas can be classified as proved reserves if the recovery of such is shown to be economically feasible.

In developing frontier areas, the existence of wells with a formation test or limited production may not be enough to classify those estimated hydrocarbon volumes as proved reserves. Issuers must demonstrate that there is reasonable certainty that a market exists for the hydrocarbons and that an economic method of extracting, treating and transporting them to market exists or is feasible and is likely to exist in the near future. A commitment by the company to develop the necessary production, treatment and transportation infrastructure is essential to the attribution of proved undeveloped reserves. Significant lack of progress on the development of such reserves may be evidence of a lack of such commitment. Affirmation of this commitment may take the form of signed sales contracts for the products; request for proposals to build facilities; signed acceptance of bid proposals; memos of understanding between the appropriate organizations and governments; firm plans and timetables established; approved authorization for expenditures to build facilities; approved loan documents to finance the required infrastructure; initiation of construction of facilities; approved environmental permits etc. Reasonable certainty of procurement of project financing by the company is a requirement for the attribution of proved reserves. An inordinately long delay in the schedule of development may introduce doubt sufficient to preclude the attribution of proved reserves.

The history of issuance and continued recognition of permits, concessions and commerciality agreements by regulatory bodies and governments should be considered when determining whether hydrocarbon accumulations can be classified as proved reserves. Automatic renewal of such agreements cannot be expected if the regulatory body has the authority to end the agreement unless there is a long and clear track record which supports the conclusion that such approvals and renewal are a matter of course.

5. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or bore hole stimulation treatment would be examples of properties with proved developed reserves since the majority of the expenditures to develop the reserves has already been spent.

Proved developed reserves from improved recovery techniques can be assigned after either the operation of an installed pilot program shows a positive production response to the technique or the project is fully installed and operational and has shown the production response anticipated by earlier feasibility studies. In the case with a pilot, proved developed reserves can be assigned only to that volume attributable to the pilot's influence. In the case of the fully installed project, response must be seen from the full project before all the proved developed reserves estimated can be assigned. If a project is not following original forecasts, proved developed reserves can only be assigned to the extent actually supported by the current performance. An important point here is that attribution of incremental proved developed reserves from the application of improved recovery techniques requires the installation of facilities and a production increase.

6. Proved undeveloped oil and gas reserves are reserves 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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with <u>certainty</u> that there is <u>continuity of production</u> from the existing productive formation. Under no circumstances should estimates of 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 tests in the area and in the same reservoir. (Emphasis added)

The SEC staff points out that this definition contains no mitigating modifier for the word certainty. Also, continuity of production requires more than the technical indication of favorable structure alone (e.g. seismic data) to meet the test for proved undeveloped reserves. Generally, proved undeveloped reserves can be claimed only for legal and technically justified drainage areas offsetting an existing productive well (but structurally no lower than LKH). If there are at least two wells in the same reservoir which are separated by more than one legal location and which show communication (reservoir continuity), proved undeveloped reserves could be claimed between the two wells, even though the location in question might be more than an offset well location away from any of the wells. In this illustration, seismic data could be used to help support this claim by showing reservoir continuity between the wells, but the required data would be the conclusive evidence of communication from production or pressure tests. The SEC staff emphasizes that proved reserves cannot be claimed more than one offset location away from a productive well if there are no other wells in the reservoir, even though seismic data may exist. The use of high-quality, well calibrated seismic data can improve reservoir description for performing volumetrics (e.g. fluid contacts). However, seismic data is not an indicator of continuity of production and, therefore, can not be the sole indicator of additional proved reserves beyond the legal and technically justified drainage areas of wells that were drilled. Continuity of production would have to be demonstrated by something other than seismic data.

In a new reservoir with only a few wells, reservoir simulation or application of generalized hydrocarbon recovery correlations would not be considered a reliable method to show increased proved undeveloped reserves. With only a few wells as data points from which to build a geologic model and little performance history to validate the results with an acceptable history match, the results of a simulation or material balance model would be speculative in nature. The results of such a simulation or material balance model would not be considered to be reasonably certain to occur in the field to the extent that additional proved undeveloped reserves could be recognized. The application of recovery correlations which are not specific to the field under consideration is not reliable enough to be the sole source for proved reserve calculations.

Reserves cannot be classified as proved undeveloped reserves based on improved recovery techniques until such time that they have been proved effective in that reservoir or an analogous reservoir in the same geologic formation in the immediate area. An analogous reservoir is one having at least the same values or better for porosity, permeability, permeability distribution, thickness, continuity and hydrocarbon saturations.

7. Topic 12 of Accounting Series Release No. 257 of the Staff Accounting Bulletins states:

> In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test.

If the combination of data from open-hole logs and core analyses is overwhelmingly in support of economic producibility and the indicated reservoir properties are analogous to similar reservoirs in the same field that have produced or demonstrated the ability to produce on a conclusive formation test, the reserves may be classified as proved. This would probably be a rare event especially in an exploratory situation. The essence of the SEC definition is that in most cases there must at least be a conclusive formation test in a new reservoir before any reserves can be considered to be proved.

8. Statement of Financial Accounting Standards 69, paragraph 30.a. requires the following disclosure:

> Future cash inflows. These shall be computed by applying year-end prices of oil and gas relating to the enterprise's proved reserves to the year-end quantities of those reserves.

This requires the use of physical pricing determined by the market on the last day of the (fiscal) year. For instance, a west Texas oil producer should determine the posted price of crude (hub spot price for gas) on the last day of the year, apply historical adjustments (transportation, gravity, BS&W, purchaser bonuses, etc.) and use this oil or gas price on an individual property basis for proved reserve estimation and future cash flow calculation (this price is also used in the application of the full cost ceiling test). A monthly average is not the price on the last day of the year, even though that may be the price received for production on the last day of the year. Paragraph 30b) states that future production costs are to be based on year-end figures with the assumption of the continuation of existing economic conditions.

9. Probabilistic methods of reserve estimating have become more useful due to improved computing and more important because of its acceptance by professional organizations such as the SPE. The SEC staff feels that it would be premature to issue any confidence criteria at this time. The SPE has specified a 90% confidence level for the determination of proved reserves by probabilistic methods. Yet, many instances of past and current practice in deterministic methodology utilize a median or best estimate for proved reserves. Since the likelihood of a subsequent increase or positive revision to proved reserve estimates should be much greater than the likelihood of a decrease, we see an inconsistency that should be resolved. If probabilistic methods are used, the limiting criteria in the SEC definitions, such as LKH, are still in effect and shall be honored. Probabilistic aggregation of proved reserves can result in larger reserve estimates (due to the decrease in uncertainty of recovery) than simple addition would yield. We require a straight forward reconciliation of this for financial reporting purposes.

10. We have seen in press releases and web sites disclosure language by oil and gas companies which would not be allowed in a document filed with the SEC. We will request that any such disclosures be accompanied by the following cautionary language:

> Cautionary Note to U.S. Investors -- The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms {in this press release/on this web site}, such as [identify the terms], that the SEC's guidelines strictly prohibit us from including in filings with the SEC. U.S. Investors are urged to consider closely the disclosure in our Form XX, File No. X-XXXX, available from us at [registrant address at which investors can request the filing]. You can also obtain this form from the SEC by calling 1-800-SEC-0330.

Examples of such disclosures would be statements regarding "probable," "possible," or "recoverable" reserves among others.

11. The SEC staff reminds professionals engaged in the practice of reserve estimating and evaluation that the Securities Act of 1933 subjects to potential civil liability every expert who, with his or her consent, has been named as having prepared or certified any part of the registration statement, or as having prepared or certified any report or valuation used in connection with the registration statement. These experts include accountants, attorneys, engineers or appraisers.

ATTACHMENT C

EXCERPT FROM
SECURITIES AND EXHANGE COMMISSION DOCUMENT
"CURRENT ISSUES AND RULEMAKING PROJECTS",
NOVEMBER 14, 2000

NOVEMBER 14, 2000

CURRENT ISSUES AND RULEMAKING PROJECTS

DIVISION OF CORPORATION FINANCE

Securities and Exchange Commission
Washington, D.C. 20549

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16. Clarification of Oil and Gas Reserve Definitions and Requirements

Over the last several years, the estimation and classification of petroleum reserves has been impacted by the development of new technologies such as 3-D seismic interpretation and reservoir simulation. Computer processor improvements have allowed the increased use of probabilistic methods in proved reserve assessments. These have led to issues of consistency and, therefore, some confusion in the reporting of proved oil and gas reserves by public issuers in their filings with the Commission. The following discussion addresses some issues the Division of Corporation Finance's engineering staff has detected in its review of these filings.

The definitions for proved oil and gas reserves for the SEC are found in Rule 4-10(a) of Regulation S-X of the Securities Exchange Act of 1934. The SEC definitions are below in bold italics. Under each section we have tried to explain the SEC staff's position regarding some of the more common issues that arise from each portion of the definitions. As most engineers who deal with the classification of reserves have come to realize, it is difficult, if not impossible, to write reserve definitions that easily cover all possible situations. Each case has to be studied as to its own unique issues. This is true with the Society of Petroleum Engineers' and others' reserve definitions as well as the SEC's definitions.

a. **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. Prices include consideration of changes in existing prices provided by contractual arrangements, but not on escalations based upon future conditions.**

The determination of **reasonable certainty** is generated by supporting geological and engineering data. There must be data available which indicate that assumptions such as decline rates, recovery factors, reservoir limits, recovery mechanisms and volumetric estimates, gas-oil ratios or liquid yield are valid. If the area in question is new to exploration and there is little supporting data for decline rates, recovery factors, reservoir drive mechanisms etc., a conservative approach is appropriate until there is enough supporting data to justify the use of more liberal parameters for the estimation of proved reserves. **The concept of reasonable certainty implies that, as more technical data becomes available, a positive, or upward, revision is much more likely than a negative, or downward, revision.**

Existing economic and operating conditions are the product prices, operating costs, production methods, recovery techniques, transportation and marketing arrangements, ownership and/or entitlement terms and regulatory requirements that are extant on the effective date of the estimate. An anticipated change in conditions must have reasonable certainty of occurrence; the corresponding investment and operating expense to make that change must be included in the economic feasibility at the appropriate time. These conditions include estimated net abandonment costs to be incurred and duration of current licenses and permits.

If oil and gas prices are so low that production is actually shut-in because of uneconomic conditions, the reserves attributed to the shut-in properties can no longer be classified as proved and must be subtracted from the proved reserve data base as a negative revision. Those volumes may be included as positive revisions to a subsequent year's proved reserves only upon their return to economic status.

b. **Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limits of the reservoir.**

Proved reserves may be attributed to a prospective zone if a conclusive formation test has been performed or if there is production from the zone at economic rates. It is clear to the SEC staff that wireline recovery of small volumes (e.g. 100 cc) or production of a few hundred barrels per day in remote locations is not necessarily conclusive. Analyses of open-hole well logs which imply that an interval is productive are not sufficient for attribution of proved reserves. If there is an indication of economic producibility by either formation test or production, the reserves in the legal and technically justified drainage area around the well projected down to a known fluid contact or the lowest known hydrocarbons, or LKH may be considered to be proved.

In order to attribute proved reserves to legal locations adjacent to such a well (i.e. offsets), there must be conclusive, unambiguous technical data which supports reasonable certainty of production of those volumes and sufficient legal acreage to economically justify the development without going below the shallower of the fluid contact or the LKH. In the absence of a fluid contact, no offsetting reservoir volume below the LKH from a well penetration shall be classified as proved.

Upon obtaining performance history sufficient to reasonably conclude that more reserves will be recovered than those estimated volumetrically down to LKH, positive reserve revisions should be made.

c. **Reserves that can be produced economically through applications of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.**

If an improved recovery technique which has not been verified by routine commercial use in the area is to be applied, the hydrocarbon volumes estimated to be recoverable cannot be classified as proved reserves unless the technique has been demonstrated to be technically and economically successful by a pilot project or installed program in that specific rock volume. That demonstration should validate the feasibility study leading to the project.

d. **Estimates of proved reserves do not include the following:**

- **oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";**
- **crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;**

- **crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects;**
- **crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other sources.**

Geologic and reservoir characteristic uncertainties such as those relating to permeability, reservoir continuity, sealing nature of faults, structure and other unknown characteristics may prevent reserves from being classified as proved. Economic uncertainties such as the lack of a market (e.g. stranded hydrocarbons), uneconomic prices and marginal reserves that do not show a positive cash flow can also prevent reserves from being classified as proved. Hydrocarbons "manufactured" through extensive treatment of gilsonite, coal and oil shales are mining activities reportable under Industry Guide 7. They cannot be called proved oil and gas reserves. However, coal bed methane gas can be classified as proved reserves if their recovery is shown to be economically feasible.

In developing frontier areas, the existence of wells with a formation test or limited production may not be enough to classify those estimated hydrocarbon volumes as proved reserves. Issuers must demonstrate that there is reasonable certainty that a market exists for the hydrocarbons and that an economic method of extracting, treating and transporting them to market exists or is feasible and is likely to exist in the near future. A commitment by the company to develop the necessary production, treatment and transportation infrastructure is essential to the attribution of proved undeveloped reserves. Significant lack of progress on the development of those reserves may be evidence of a lack of such a commitment. Affirmation of this commitment may take the form of signed sales contracts for the products; request for proposals to build facilities; signed acceptance of bid proposals; memos of understanding between the appropriate organizations and governments; firm plans and timetables established; approved authorization for expenditures to build facilities; approved loan documents to finance the required infrastructure; initiation of construction of facilities; approved environmental permits etc. Reasonable certainty of procurement of project financing by the company is a requirement for the attribution of proved reserves. An inordinately long delay in the schedule of development may introduce doubt sufficient to preclude the attribution of proved reserves.

The history of issuance and continued recognition of permits, concessions and commerciality agreements by regulatory bodies and governments should be considered when determining whether hydrocarbon accumulations can be classified as proved reserves. Automatic renewal of those agreements cannot be expected if the regulatory body has the authority to end the agreement unless there is a long and clear track record which supports the conclusion that those approvals and renewal are a matter of course.

e. **Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.**

Currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or bore hole stimulation treatment would be examples of properties with proved developed reserves since the majority of the expenditures to develop the reserves has already been spent.

Proved developed reserves from **improved recovery techniques** can be assigned after either the operation of an installed pilot program shows a positive production response to the technique or the project is fully installed and operational and has shown the production response anticipated by earlier feasibility studies. In the case with a pilot, proved developed reserves can be assigned only to that volume attributable to the pilot's influence. In the case of the fully installed project, response must be seen from the full project before all the proved developed reserves estimated can be assigned. If a project is not following original forecasts, proved developed reserves can only be assigned to the extent actually supported by the current performance. An important point here is that attribution of incremental proved developed reserves from the application of improved recovery techniques requires the installation of facilities and a production increase.

f. **Proved undeveloped oil and gas reserves are reserves 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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with <u>certainty</u> that there is <u>continuity of production</u> from the existing productive formation. Under no circumstances should estimates of proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other**

> **improved recovery technique is contemplated, unless those techniques have been proved effective by actual tests in the area and in the same reservoir.** (Emphasis added)

The SEC staff points out that this definition contains no mitigating modifier for the word *certainty.* Also, *continuity of production* requires more than the technical indication of favorable structure alone (e.g. seismic data) to meet the test for proved undeveloped reserves. Generally, proved undeveloped reserves can be claimed only for legal and technically justified drainage areas offsetting an existing productive well (but structurally no lower than LKH). If there are at least two wells in the same reservoir which are separated by more than one legal location and which show communication (reservoir continuity), proved undeveloped reserves could be claimed between the two wells, even though the location in question might be more than an offset well location away from any of the wells. In this illustration, seismic data could be used to help support this claim by showing reservoir continuity between the wells, but the required data would be the conclusive evidence of communication from production or pressure tests. The SEC staff emphasizes that proved reserves cannot be claimed more than one offset location away from a productive well if there are no other wells in the reservoir, even though seismic data may exist. The use of high-quality, well calibrated seismic data can improve reservoir description for performing volumetrics (e.g. fluid contacts). However, seismic data is not an indicator of continuity of production and, therefore, can not be the sole indicator of additional proved reserves beyond the legal and technically justified drainage areas of wells that were drilled. Continuity of production would have to be demonstrated by something other than seismic data.

In a new reservoir with only a few wells, reservoir simulation or application of generalized hydrocarbon recovery correlations would not be considered a reliable method to show increased proved undeveloped reserves. With only a few wells as data points from which to build a geologic model and little performance history to validate the results with an acceptable history match, the results of a simulation or material balance model would be speculative in nature. The results of such a simulation or material balance model would not be considered to be reasonably certain to occur in the field to the extent that additional proved undeveloped reserves could be recognized. The application of recovery correlations which are not specific to the field under consideration is not reliable enough to be the sole source for proved reserve calculations.

Reserves cannot be classified as proved undeveloped reserves based on improved recovery techniques until they have been proved effective in that reservoir or an analogous reservoir in the same geologic formation in the immediate area. An analogous reservoir is one having at least the same values or better for porosity, permeability, permeability distribution, thickness, continuity and hydrocarbon saturations.

g. Topic 12 of Accounting Series Release No. 257 of the Staff Accounting Bulletins states:

In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test.

If the combination of data from open-hole logs and core analyses is overwhelmingly in support of economic producibility and the indicated reservoir properties are analogous to similar reservoirs in the same field which have produced or demonstrated the ability to produce on a conclusive formation test, the reserves may be classified as proved. This would probably be a rare event especially in an exploratory situation. The essence of the SEC definition is that in most cases there must at least be a conclusive formation test in a new reservoir before any reserves can be considered to be proved.

h. Statement of Financial Accounting Standards 69, paragraph 30.a. requires the following disclosure:

Future cash inflows. **These shall be computed by applying year-end prices of oil and gas relating to the enterprise's proved reserves to the year-end quantities of those reserves.** (Emphasis added)

This requires the use of physical pricing determined by the market on the last day of the (fiscal) year. For instance, a west Texas oil producer should determine the posted price of crude (hub spot price for gas) on the last day of the year, apply historical adjustments (transportation, gravity, BS&W, purchaser bonuses, etc.) and use this oil or gas price on an individual property basis for proved reserve estimation and future cash flow calculation (this price is also used in the application of the full cost ceiling test). A monthly average is not the price on the last day of the year, even though that may be the price received for production on the last day of the year.

Paragraph 30b) states that future production costs are to be based on year-end figures with the assumption of the continuation of existing economic conditions.

i. Position on Probabilistic Methods of Reserve Estimating

Probabilistic methods of reserve estimating have become more useful due to improved computing and more important because of its acceptance by professional organizations such as the SPE. The SEC staff feels that it would be premature to issue any confidence criteria at this time. The SPE has specified a 90% confidence level for the determination of proved reserves by probabilistic methods. Yet, many instances of past and current practice in deterministic methodology utilize a median or best estimate for proved reserves. Since the likelihood of a subsequent increase or positive revision to proved reserve estimates should be much greater than the likelihood of a decrease, we see an inconsistency that should be resolved. If probabilistic methods are used, the limiting criteria in the SEC definitions, such as LKH, are still in effect and shall be honored. Probabilistic aggregation of proved reserves can result in larger reserve estimates (due to the decrease in uncertainty of recovery) than simple addition would yield. We require a straight forward reconciliation of this for financial reporting purposes.

j. Use of Cautionary Note in Connection with Disclosure Language

We have seen in press releases and web sites disclosure language by oil and gas companies which would not be allowed in a document filed with the SEC. We will request that these disclosures be accompanied by the following cautionary language:

> ***Cautionary Note to U.S. Investors -- The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms*** **{in this press release/on this web site}*****, such as*** **[identify the terms]*****, that the SEC's guidelines strictly prohibit us from including in filings with the SEC. U.S. Investors are urged to consider closely the disclosure in our Form XX, File No. X-XXXX, available from us at*** **[registrant address at which investors can request the filing]*****. You can also obtain this form from the SEC by calling 1-800-SEC-0330.***

Examples of these disclosures would be statements regarding "probable," "possible," or "recoverable" reserves among others.

k. Consent of Experts and Potential Civil Liability

The SEC staff reminds professionals engaged in the practice of reserve estimating and evaluation that the Securities Act of 1933 subjects to potential civil liability every expert who, with his or her consent, has been named as having prepared or certified any part of the registration statement, or as having prepared or certified any report or valuation used in connection with the registration statement. These experts include accountants, attorneys, engineers or appraisers.

FORREST A. GARB & ASSOCIATES, INC.

ATTACHMENT D

EXCERPT FROM
SECURITIES AND EXHANGE COMMISSION DOCUMENT
"FREQUENTLY REQUESTED ACCOUNTING AND FINANCIAL REPORTING INTERPRETATIONS AND GUIDANCE",
MARCH 31, 2001

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U.S. Securities and Exchange Commission

Division of Corporation Finance: Frequently Requested Accounting and Financial Reporting Interpretations and Guidance

Prepared by Accounting Staff Members in the Division of Corporation Finance U.S. Securities and Exchange Commission, Washington, D.C.

March 31, 2001

CONTENTS

Only in exceptional cases may inventory properly be stated at an amount above cost. Accounting Research Bulletin (ARB) No. 43, *Restatement and Revision of Accounting Research Bulletins,* cites the exceptional example of precious metals having a fixed monetary value with no substantial cost of marketing. That guidance goes on to specify criteria that must be met by any inventory carried above its cost:

- inability to determine appropriate approximate costs;
- immediate marketability at quoted market price; and
- unit interchangeability.

Only when all these criteria are met should management consider accounting for inventory at amounts above cost. The staff believes the criteria in ARB 43 are even more rarely satisfied today than in 1953 when ARB 43 was published. For example, the availability of sophisticated cost accounting techniques and supporting software suggests that few, if any, registrants are unable to approximate the appropriate cost of inventory.

Also, the criteria of "immediately marketability" and "unit interchangeability" are not met by items that are in-process and not yet in final marketable form. For example, until precious or base metals are in the final refined state in which they are typically marketed, the items are not immediately marketable nor do they have the characteristic of unit interchangeability. Mined ore, yet to be subjected to refining or smelting processes, should not be carried at an amount above cost.

Registrants should ensure that their accounting policies for in-process inventory conform to the guidance in ARB 43. SAB 101 reminds registrants that authoritative literature takes precedence over industry practice that is contrary to generally accepted accounting principles.

3. Definition of Proved Reserves

Over the last several years, the estimation and classification of petroleum reserves has been impacted by the development of new technologies such as 3-D seismic interpretation and reservoir simulation. Computer processor improvements have allowed the increased use of probabilistic methods in proved reserve assessments. These have led to issues of consistency and, therefore, some confusion in the reporting of proved oil and gas reserves by public issuers in their filings with the Commission. This section discusses some issues the Division of Corporation Finance's engineering staff has identified in its review of such filings.

The definitions for proved oil and gas reserves for the SEC are found in Rule 4-10(a) of Regulation S-X of the Securities Exchange Act of 1934. The SEC definitions are below in bold italics. Under each section we have tried to explain the SEC staff's position regarding some of the more common issues that arise from each portion of the definitions. As most engineers who deal with the classification of reserves have come to realize, it is difficult, if not impossible, to write reserve definitions that easily cover all possible situations. Each case has to be studied as to its own unique issues. This is true with the Society of Petroleum Engineers' and others' reserve definitions as well as the SEC's definitions.

(a) 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. Prices include consideration of changes in existing prices provided by contractual arrangements, but not on escalations based upon future conditions.

The determination of reasonable certainty is generated by supporting geological and engineering data. There must be data available which indicate that assumptions such as decline rates, recovery factors, reservoir limits, recovery mechanisms and volumetric estimates, gas-oil ratios or liquid yield are valid. If the area in question is new to exploration and there is little supporting data for decline rates, recovery factors, reservoir drive mechanisms etc., a conservative approach is appropriate until there is enough supporting data to justify the use of more liberal parameters for the estimation of proved reserves. The concept of reasonable certainty implies that, as more technical data becomes available, a positive, or upward, revision is much more likely than a negative, or downward, revision.

Existing economic and operating conditions are the product prices, operating costs, production methods, recovery techniques, transportation and marketing arrangements, ownership and/or entitlement terms and regulatory requirements that are extant on the effective date of the estimate. An anticipated change in conditions must have reasonable certainty of occurrence; the corresponding investment and operating expense to make that change must be included in the economic feasibility at the appropriate time. These conditions include estimated net abandonment costs to be incurred and duration of current licenses and permits.

If oil and gas prices are so low that production is actually shut-in because of uneconomic conditions, the reserves attributed to the shut-in properties can no longer be classified as proved and must be subtracted from the proved reserve data base as a negative revision. Those volumes may be included as positive revisions to a subsequent year's proved reserves only upon their return to economic status.

(b) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limits of the reservoir.

Proved reserves may be attributed to a prospective zone if a conclusive formation test has been performed or if there is production from the zone at economic rates. It is clear to the SEC staff that wireline recovery of small volumes (e.g. 100 cc) or production of a few hundred barrels per day in remote locations is not necessarily conclusive. Analyses of open-hole well logs which imply that an interval is productive are not sufficient for attribution of proved reserves. If there is an indication of economic producibility by either formation test or production, the reserves in the legal and technically justified drainage area around the well projected down to a known fluid contact or the lowest known hydrocarbons, or LKH may be considered to be proved.

In order to attribute proved reserves to legal locations adjacent to such a well (i.e. offsets), there must be conclusive, unambiguous technical data which supports reasonable certainty of production of such volumes and sufficient legal acreage to economically justify the development without going below the shallower of the fluid contact or the LKH. In the absence of a fluid contact, no offsetting reservoir volume below the LKH from a well penetration shall be classified as proved.

Upon obtaining performance history sufficient to reasonably conclude that more reserves will be recovered than those estimated volumetrically down to LKH, positive reserve revisions should be made.

(c) Reserves which can be produced economically through applications of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

If an improved recovery technique which has not been verified by routine commercial use in the area is to be applied, the hydrocarbon volumes estimated to be recoverable cannot be classified as proved reserves unless the technique has been demonstrated to be technically and economically successful by a pilot project or installed program in that specific rock volume. Such demonstration should validate the feasibility study leading to the project.

(d) Estimates of proved reserves do not include the following:

- oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";
- crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
- crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects;
- crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other sources.

Geologic and reservoir characteristic uncertainties such as those relating to permeability, reservoir continuity, sealing nature of faults, structure and other unknown characteristics may prevent reserves from being classified as proved. Economic uncertainties such as the lack of a market (e.g. stranded hydrocarbons), uneconomic prices and marginal reserves that do not show a positive cash flow can also prevent reserves from being classified as proved. Hydrocarbons "manufactured" through extensive treatment of gilsonite, coal and oil shales are mining activities reportable under Industry Guide 7. They cannot be called proved oil and gas reserves. However, coal bed methane gas can be classified as proved reserves if the recovery of such is shown to be economically feasible.

In developing frontier areas, the existence of wells with a formation test or limited production may not be enough to classify those estimated hydrocarbon volumes as proved reserves. Issuers must demonstrate that there is reasonable certainty that a market exists for the hydrocarbons and that an economic method of extracting, treating and transporting them to market exists or is feasible and is likely to exist in the near future. A commitment by the company to develop the necessary production, treatment and transportation infrastructure is essential to the attribution of proved undeveloped reserves. Significant lack of progress on the development of such reserves may be evidence of a lack of such commitment. Affirmation of this commitment may take the form of signed sales contracts for the products; request for proposals to build facilities; signed acceptance of bid proposals; memos of understanding between the appropriate organizations and governments; firm plans and timetables established; approved authorization for expenditures to build facilities; approved loan documents to finance the required infrastructure; initiation of construction of facilities; approved environmental permits etc. Reasonable certainty of procurement of project financing by the company is a requirement for the attribution of proved reserves. An inordinately long delay in the schedule of development may introduce doubt sufficient to preclude the attribution of proved reserves.

The history of issuance and continued recognition of permits, concessions and commerciality agreements by regulatory bodies and governments should be considered when determining whether hydrocarbon accumulations can be classified as proved reserves. Automatic renewal of such agreements cannot be expected if the regulatory body has the authority to end the agreement unless there is a long and clear track record which supports the conclusion that such approvals and renewal are a matter of course.

(e) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or bore hole stimulation treatment would be examples of properties with proved developed reserves since the majority of the expenditures to develop the reserves has already been spent.

Proved developed reserves from improved recovery techniques can be assigned after either the operation of an installed pilot program shows a positive production response to the technique or the project is fully installed and operational and has shown the production response anticipated by earlier feasibility studies. In the case with a pilot, proved developed reserves can be assigned only to that volume attributable to the pilot's influence. In the case of the fully installed project, response must be seen from the full project before all the proved developed reserves estimated can be assigned. If a project is not following original forecasts, proved developed reserves can only be assigned to the extent actually supported by the current performance. An important point here is that attribution of incremental proved developed reserves from the application of improved recovery techniques requires the installation of facilities and a production increase.

(f) Proved undeveloped oil and gas reserves are reserves 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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates of 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 tests in the area and in the same reservoir. (Emphasis added)

The SEC staff points out that this definition contains no mitigating modifier for the word certainty. Also, continuity of production requires more than the technical indication of favorable structure alone (e.g. seismic data) to meet the test for proved undeveloped reserves. Generally, proved undeveloped reserves can be claimed only for legal and technically justified drainage areas offsetting an existing productive well (but structurally no lower than LKH). If there are at least two wells in the same reservoir which are separated by more than one legal location and which show communication (reservoir continuity), proved undeveloped reserves could be claimed between the two wells, even though the location in question might be more than an offset well location away from any of the wells. In this illustration, seismic data could be used to help support this claim by showing reservoir continuity between the wells, but the required data would be the conclusive evidence of communication from production or pressure tests. The SEC staff emphasizes that proved reserves cannot be claimed more than one offset location away from a productive well if there are no other wells in the reservoir, even though seismic data may exist. The use of high-quality, well calibrated seismic data can improve reservoir description for performing volumetrics (e.g. fluid contacts). However, seismic data is not an indicator of continuity of production and, therefore, can not be the sole indicator of additional proved reserves beyond the legal and technically justified drainage areas of wells that were drilled. Continuity of production would have to be demonstrated by something other than seismic data.

In a new reservoir with only a few wells, reservoir simulation or application of generalized hydrocarbon recovery correlations would not be considered a reliable method to show increased proved undeveloped reserves. With only a few wells as data points from which to build a geologic model and little performance history to validate the results with an acceptable history match, the results of a simulation or material balance model would be speculative in nature. The results of such a simulation or material balance model would not be considered to be reasonably certain to occur in the field to the extent that additional proved undeveloped reserves could be recognized. The application of recovery correlations which are not specific to the field under consideration is not reliable enough to be the sole source for proved reserve calculations.

Reserves cannot be classified as proved undeveloped reserves based on improved recovery techniques until such time that they have been proved effective in that reservoir or an analogous reservoir in the same geologic formation in the immediate area. An analogous reservoir is one having at least the same values or better for porosity, permeability, permeability distribution, thickness, continuity and hydrocarbon saturations.

(g) Topic 12 of Accounting Series Release No. 257 of the Staff Accounting Bulletins states:

> In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test.

If the combination of data from open-hole logs and core analyses is overwhelmingly in support of economic producibility and the indicated reservoir properties are analogous to similar reservoirs in the same field that have produced or demonstrated the ability to produce on a conclusive formation test, the reserves may be classified as proved. This would probably be a rare event especially in an exploratory situation. The essence of the SEC definition is that in most cases there must at least be a conclusive formation test in a new reservoir before any reserves can be considered to be proved.

(h) Statement of Financial Accounting Standards 69, paragraph 30.a. requires that "Future cash inflows . . . be computed by applying year-end prices of oil and gas relating to the enterprise's proved reserves to the year-end quantities of those reserves. This requires the use of physical pricing determined by the market on the last day of the (fiscal) year. For instance, a west Texas oil producer should determine the posted price of crude (hub spot price for gas) on the last day of the year, apply historical adjustments (transportation, gravity, BS&W, purchaser bonuses, etc.) and use this oil or gas price on an individual property basis for proved reserve estimation and future cash flow calculation (this price is also used in the application of the full cost ceiling test). A monthly average is not the price on the last day of the year, even though that may be the price received for production on the last day of the year. Paragraph 30b) states that future production costs are to be based on year-end figures with the assumption of the continuation of existing economic conditions.

(i) Probabilistic methods of reserve estimating have become more useful due to improved computing and more important because of its acceptance by professional organizations such as the SPE. The SEC staff feels that it would be premature to issue any confidence criteria at this time. The SPE has specified a 90% confidence level for the determination of proved reserves by probabilistic methods. Yet, many instances of past and current practice in deterministic methodology utilize a median or best estimate for proved reserves. Since the likelihood of a subsequent increase or positive revision to proved reserve estimates should be much greater than the likelihood of a decrease, we see an inconsistency that should be resolved. If probabilistic methods are used, the limiting criteria in the SEC definitions, such as LKH, are still in effect and shall be honored. Probabilistic aggregation of proved reserves can result in larger reserve estimates (due to the decrease in uncertainty of recovery) than simple addition would yield. We require a straight forward reconciliation of this for financial reporting purposes.

(j) The calculation of the standardized measure of discounted future net cash flows relating to oil and gas properties must comply with paragraph 30 of SFAS 69. The effects of income taxes, like all other elements of the measure, must be discounted at the standard rate of 10% pursuant to paragraph 30(e). The "short-cut" method for determining the tax effect on the ceiling test for companies using the full-cost method of accounting, as described in SAB Topic 12:D:1, Question 2, may not be used for purposes of the paragraph 30 calculation of the standardized measure.

(k) We have seen in press releases and web sites disclosure language by oil and gas companies which would not be allowed in a document filed with the SEC. We will request that any such disclosures be accompanied by the following cautionary language:

> Cautionary Note to U.S. Investors -- The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms {in this press release/on this web site}, such as [identify the terms], that the SEC's guidelines strictly prohibit us from including in filings with the SEC. U.S. Investors are urged to consider closely the disclosure in our Form XX, File No. X-XXXX, available from us at [registrant address at which investors can request the filing]. You can also obtain this form from the SEC by calling 1-800-SEC-0330.

Examples of such disclosures would be statements regarding "probable," "possible," or "recoverable" reserves among others.

(l) Under Production Sharing Agreements, a host government typically retains the title to the hydrocarbons in place, although the contracting company usually assumes all the costs for exploration and carries all risks. When a discovery is made, the contract provides for the contracting company to recover all its exploration and development expenditures and receive a share of profits, subject to certain limits. The amounts due to the contracting company are typically taken in kind.

In general, two methods of determining oil and gas reserves under production sharing arrangements have been proposed by registrants: (a) the working interest method and (b) the economic interest method. Under the working interest method, the estimate for total proved reserves is multiplied by the respective working interest held by the contracting company, net of any royalty. Under the economic interest method, the company's share of the cost recovery oil revenue and the profit oil revenue is divided by the year-end oil price, which represents the volume entitlement. The lower the oil price, the higher the barrel entitlement, and vice versa.

Reserve volumes determined by various owners should add up to 100% of the total field reserves, but that is not always the case using the working interest method. If the working interest is different from the profit entitlement, the economic interest method is the method acceptable to the staff because it is a closer representation of the actual reserve volume entitlement that can be monetized by a company. Also, use of the economic interest method avoids violating the prohibition in paragraph 10 of SFAS 69 against reporting reserves owned by others.

(m) The SEC staff reminds professionals engaged in the practice of reserve estimating and evaluation that the Securities Act of 1933 subjects to potential civil liability every expert who, with his or her consent, has been named as having prepared or certified any part of the registration statement, or as having prepared or certified any report or valuation used in connection with the registration statement. These experts include accountants, attorneys, engineers or appraisers.

4. Goodwill and Purchase Business Combinations

The staff often has challenged recognition of goodwill in acquisitions of entities whose dominant business is the ownership and operation of oil and gas or mineral properties. In the absence of other substantial business activities, the staff presumes that substantially all the value of the acquired entity not otherwise accounted for by tangible and identifiable intangible assets is derived from the value of the mineral or oil and gas reserves owned by that entity. In these business combinations, the purchase price ordinarily should be allocated entirely to the properties and other net tangible and identifiable intangible assets acquired, with no allocation to goodwill. However, if an excess purchase price is clearly indicated by

ATTACHMENT E

RESUME OF MR. WILLIAM D. HARRIS III

FORREST A. GARB & ASSOCIATES, INC.

WILLIAM DONALD HARRIS III, P.E.
Chief Executive Officer
Forrest A. Garb & Associates, Inc.
B.S. - Petroleum Engineering, Texas A&M University
M.B.A. - Southern Methodist University

Mr. Harris received his petroleum engineering degree in May 1984 and began his career with ARCO Oil & Gas Company in Houston as a Reservoir Engineer. He conducted engineering evaluations designed to maximize productivity of offshore oil and gas fields through development drilling, recompletions, stimulations, and remedial work. Mr. Harris also performed economic evaluations of extension and exploration prospects.

Mr. Harris continued his education at Southern Methodist University of Dallas, Texas, where he received his Master of Business Administration in August 1988.

From September 1988 to August 1990, Mr. Harris worked as a Consulting Engineer for J.R. Latimer Jr., Inc. in Dallas, managing properties in Texas, Louisiana, Alabama, Nevada, California, and Canada for a family estate. He conducted independent evaluations of reserves for possible acquisitions and tax purposes.

Mr. Harris joined DeGolyer and MacNaughton of Dallas in 1990 and was made a Vice President in 1995. He prepared reserve and appraisal reports for oil and gas fields in Peru, Indonesia, Myanmar, Pakistan, and Thailand, and to support an IPO for a joint venture project in Indonesia.

In 1998, Mr. Harris joined FGA and is the Chief Executive Officer. He continues to perform engineering studies on both domestic and international projects.

He is a member of the SPE and was Membership Chairman from 1980 to 1984. He was on the Dean's Honor Roll of Texas A&M University in 1980 and 1983. He was a Distinguished Student from 1980 to 1983. Mr. Harris was a member of Tau Beta Pi, National Engineering Honor Society (1982-1984), and was Vice President of the Petroleum Engineering Honor Society of Pi Epsilon Tau (1982-1984). Mr. Harris has authored multiple articles in World Oil magazine since 2001. Mr. Harris is a registered professional engineer in the state of Texas.

ATTACHMENT E

ATTACHMENT F

PUBLICATIONS OF MR. WILLIAM D. HARRIS III

FORREST A. GARB & ASSOCIATES, INC.

PUBLICATIONS OF MR. WILLIAM D. HARRIS III

1) Harris, W.D.: "Slow Improvement Seen for Consultants," World Oil, (December 2001) 45-46.

2) Harris, W.D.: "Consultant Sector Bides It's Time," World Oil, (December 2002) 30.

3) Harris, W.D.: "Industry Survives With Newfound Maturity," World Oil, (December 2003) 23.

4) Harris, W.D.: "Consultants Strive to Keep Pace with Operators' Plans," World Oil, (December 2004) 31-32.

5) Harris, W.D.: "High Prices Boost Consultants' Work Loads," World Oil, (December 2005) 30-31.

ATTACHMENT F

ATTACHMENT G

COMPENSATION OF MR. WILLIAM D. HARRIS III

FORREST A. GARB & ASSOCIATES, INC.

COMPENSATION OF MR. WILLIAM D. HARRIS III

Mr. William D. Harris III is compensated at a rate of $175 per hour for work performed on this assignment with the exception of depositions and expert testimony. Mr. Harris is compensated at a rate of $225 per hour for depositions and expert testimony.

ATTACHMENT G

ATTACHMENT H

HISTORY OF EXPERT TESTIMONY AND DEPOSITION OF MR. WILLIAM D. HARRIS III WITHIN THE PRECEDING FOUR YEARS

FORREST A. GARB & ASSOCIATES, INC.

**HISTORY OF EXPERT TESTIMONY AND DEPOSITION OF
MR. WILLIAM D. HARRIS III
WITHIN THE PRECEDING FOUR YEARS**

1) Union Oil Company of California (Unocal) vs. Agrium, Imc.
No. 7OT1980053902
(American Arbitration Association)
Susman Godfrey, LLP
April 2004

ATTACHMENT H