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U.S. Securities and Exchange Commission
100 F Street, NE
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Attention: Nancy M. Morris, Secretary

U.S. Securities and Exchange Commission
Comments on Concept Release on
Possible Revisions to the Disclosure Requirements
Relating to Oil and Gas Reserves

Introduction

The following comments are in reply to the U.S. Securities and Exchange Commission's (SEC) Concept Release No: 33-8870 published on December 12, 2007 to obtain information about the extent and nature of the public's interest in revising oil and gas reserves disclosure requirements which exist in their current form in Regulation S-K and Regulation S-X under the Secuities Act of 1933 and Securities Exchange Act of 1934. The Commission adopted the current oil and reserves disclosure requirements between 1978 and 1982.

The comments which are presented herein are based on the author's 40 years of experience in the oil and gas industry. He has evaluated oil and gas reserves while employed with a major worldwide independent evaluation firm, spearheaded the development of the Canadian Oil and Gas Evaluation Handbook (COGEH), and assisted the Alberta Secuities Commission (ASC) by co-authoring the writing of National Instrument 51-101 (NI 51-101) "Standards of Disclosure for Oil and Gas Activities". Currently he is assisting several oil and gas companies in the preparation of their annual disclosure Form NI 51-101 F1 "Statement of Reserves Data and Other Oil and Gas Information".

The majority of the comments in this document pertain to the Reserves Definitions and Evaluation Practices and Procedures presented in the COGEH and in NI 51-101 Standards of Disclosure for Oil and Gas Activities that were developed in Canada and have been in use for over four years. The comments will only provide summaries of pertinent information contained in the COGEH and in NI 51-101.

For more detailed information, please refer to these documents which can be obtained from:

- COGEH Volumes 1,2,3: www.petsoc.org
- NI 51-101: www.albertasecurities.com

Other comments will also be provided by the author to futher advance the information included in the COGEH and in NI 51-101.

Disclaimer

The comments presented in this report express the sole opinions of the author, Mr. J. Glenn Robinson, P. Eng., and may not necessarily represent those of the authors of the COGEH or NI 51-101.

Qualifications of J. Glenn Robinson, P. Eng.

J. Glenn Robinson, P.Eng. is a fully Qualified Reserves Evaluator and Auditor as defined in the COGEH. A summary of his curriculum vitae, relative to oil and gas reserves disclosure requirements follows:

- B.Sc. (Honours) Civil Engineering, Queen's University, Kingston, Ontario, Canada.
- Major Employers:
    - Shell Canada Ltd. (1966 – 1971)
    - Scientific Software of Canada Ltd. (1971 – 1973)
    - Sproule Associates Limited (1973 – 2000) – President (1992 – 2000
    - Robinson Petroleum Consulting Ltd. (2000- Present) - President
- Professional Memberships:
    - Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA)
    - Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum (CIM)
    - Society of Petroleum Evaluation Engineers (SPEE)
- Spearheaded the publication of the COGEH
- Assisted in co-authoring NI 51-101
- Publications and Presentations:
    - Numerous papers and presentations on "Oil and Reserves Estimations and Evaluation Practices" within Canada and the United States and in other International Countries
- Teaching Assignments:
    - Teaching courses on "Evaluation of Oil and Gas Reserves" and "Risk Analyses of Oil and Gas Properties" within Canada and the United States and in other International Countries.

SEC Questions

(1) Should the Rules-Based Rules be replaced with Principles-Based Rules?

It is highly recommended that the Rules-Based Rules be replaced with Principles-Based Rules. The existing SEC Rules-Based Rules is a Comparison Index that basically suffices as a comparison tool, but offers little more to the investment community. Business decisions in the oil and gas industry are based on Principles-Based Rules or as often referred to as a Value Concept. The Value Concept, as the name suggests, provides data from which the worth of the upstream assets of an oil and gas company can be determined. Both Reserves and Resources should be evaluated and reported to give a complete evaluation of a company's upstream assets. This latter system complies with the "Full, True and Plain" disclosure of a company's oil and gas activities and provides an investor with a great deal of information about a company's value allowing sound investment decisions to be made.

Specific Evaluation Rules in the evaluation procedure creates difficulties for the evaluator because every reservoir has different geological settings and rock properties and always contains different mixtures of hydrocarbons and non-hydrocarbon fluids. When situations arise for which the rules don't apply, evaluators tend to bend the rules, often resulting in poor evaluation results. The only Fixed and Hard Rule that must be adhered to in the evaluation process is that "a reservoir must have been penetrated by a wellbore before reserves can be assigned", otherwise only resources can be considered.

The principles used in the evaluation process must be left up to Qualified Reserves and Resources Evaluators who, as professionals, must use sound geological and engineering practices or else face discipinary action from their professional organization. The monitoring of evaluators and evaluations will be discussed later.

(2) Should companies be allowed to disclose Reserves and Resources other than Proved Reserves?

As noted in Question 1, in order to ensure that the market and investors receive "Full, True and Plain" disclosure, companies must disclose all categories of reserves and resources. The definitions and categorization of reserves and resources will be discussed in Question 3.

(3) Should the Commission adopt all or part of the Society of Petroleum Engineers (SPE) Petroleum Resources Management System (PRMS) or other classification frameworks? How should the Commission respond if that system is changed in the future?

The recently published SPE – PRMS System is very closely aligned with the Canadian system as specified in the COGEH. The SPE system is relatively new, whereas, the Canadian system has been in place since September 30, 2003 and has been successfully tried and proven during the past four years.

The purpose of the NI 51-101 was to enhance the quality, consistency, timeliness and comparabilty of public disclosure by reporting issuers concerning their upstream oil and gas activities. The new standards were designed to enhance investor confidence in the Canadian capital markets and to facilitate the raising of new capital by oil and gas reporting issuers. The Canadian Securities Administrators (CSA) are of the view that information about oil and gas reserves and activities is essential to enable investors to make informed investment decisions concerning securities of upstream oil and gas issuers. It is the belief that investors and capital markets are entitled to information that:

- reflects the conclusions of Professional Qualified Reserves and Resources Evaluators applying consistent standards

- is given appropriate attention by management and directors
- is provided on a regular basis and,
- is presented in a manner that facilitates comparison among reporting issuers and over time.

To accomplish these objectives, NI 51-101 establishes disclosure standards and procedures somewhat akin to those long applied to financial disclosure. It prescribes standards for the preparation and disclosure of oil and gas reserves and resources and related estimates, requires the annual public filing of certain of those estimates and other information pertaining to oil and gas activities, and specifies responsibilities of corporate directors.

There is little doubt that the NI 51-101 disclosure system has met the objectives of the CSA. Furthermore, the procedures for evaluating reserves and resources, as presented in the COGEH, have also been accepted and withstood the scrutiny of professional qualified reserves evaluators and auditors. COGEH Volume 1 was published on June 30, 2002. It is noteworthy that the Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA) has adopted the COGEH as their "Practice Standards for Evaluation of Oil and Gas Reserves for Public Disclosure".

The concern as to how the Commission should respond to changing reserves and resources systems has been handled automatically in the Canadian system. Throughout the NI 51-101 "Standards of Disclosure", all issues pertaining to the evaluation of reserves and resources are referenced to the appropriate procedure in the COGEH. Therefore, as procedures in COGEH change, so does NI 51-101 change. As changes occur in either NI 51-101 or in the COGEH, appropriate approvals are made between the ASC and the Calgary Chapter of SPEE (authors of COGEH).

(4) Should the Commission revise the current definitions of Proved Reserves, Proved Developed Reserves and Proved Undeveloped Reserves and if so, how?

In order to keep pace with the emerging reserves and resources classification systems in the oil and gas industry, the Commission should revise their current definitions. The classification system that is suggested is that used in Canada and presented in the COGEH Volume 1. The details of the COGEH "Definitions of Resources and Reserves" can be downloaded from the ASC website:

www.albertasecurities.com/COMPANIES/Pages/OilGas.aspx.

In summary, the COGEH definitions stipulates the following major categories of reserves:

Proved Reserves	(P_V)
Probable Reserves	(P_B)
Possible Reserves	(P_S)

Each major classification is further sub-divided into the following producing and development statuses:

Proved

Developed Producing	(P_VDP)
Developed Non-Producing	(P_VDNP)
Undeveloped	(P_VUD)

Probable

Developed Producing	(P_BDP)
Developed Non-Producing	(P_BDNP)
Undeveloped	(P_BUD)

Possible

Developed Producing	(P_SDP)
Developed Non-Producing	(P_SDNP)
Undeveloped	(P_SUD)

The major reserve categories can be aggregated as follows:

Proved	($1P = P_V$)
Proved + Probable	($2P = P_V + P_B$)
Proved + Probable + Possible	($3P = P_V + P_B + P_S$)

The COGEH definitions uses statistical confidence levels to better define the reserve categories. Confidence levels, such as $P_{90,}$ means that there is a 90 percent probability that a result will be equal to or greater than the P_{90} estimate.The confidence levels for the major reserves categories are:

Major Reserves Confidence Levels

Aggregated Major Reserves Classifications	Entity Level	Total Company Level
1P	High Degree of Certainty of Recovery	At Least P_{90}
2P	Equally Likely to be or not to be Recovered	P_{50}
3P	Unlikely to be Recovered	P_{10}

An Entity refers to the lowest level of a reserves evaluation. It may be a single well, a group of wells, a pool or a field or often an oil and gas production unit. The Total Company Level is the aggregation of all of the company's entities.

Unfortunately, at this time, the majority of evaluators are reluctant to place confidence levels at the Entity Level. When statistical concepts do become completely accepted, hopefully in the near future, P_{90}, P_{50}, and P_{10} or similar confidence levels will also be applied at the entity level for 1P, 2P, and 3P reserves estimates. More discussion will be made on statistical concepts later in this report.

It is important to understand that the major reserve categories are not unique and not mutually exclusive. They are all part of an estimate where the P_{50} is the Median value and the P_{90} and P_{10} confidence levels provide low and high estimates within the distribution of possible estimates. The low and high estimates (1P and 3P) are only included to provide a measure of dispersion of the data about the P_{50} value. Also, the producing and development sub-categories have the same confidence levels as the respective major reserve category.

The P_{50} value is the Median value in a distribution of possible estimates. It means that there is equal probability (50 percent) that the result will be less than or greater than the P_{50} value The P_{50} is <u>not</u> the Mean (Expected or Best Estimate) or the Mode (Most Likely Estimate). Also, the confidence levels do not equate with the probability that an event will occur. For example, the P_{90} confidence level for 1P reserves means that there is a 90 percent probability that at least the P_{90} reserves will be recovered. Actually, the probability of recovering approximately the P_{90} reserves is very small, probably less that 10 percent.

(5) Should the Commission specify the tests required to estimate reserves?

The guidelines to be used for a specific set of reserves and resource definitions should be developed by Qualified Reserves Evaluators, either within the Commission or preferably by Professional Societies such as the SPE or SPEE. In Canada, these guidelines were prepared by members of the Calgary Chapter of the SPEE. They are included in the COGEH Volume 2 for conventional oil and gas production. Some of the major topics covered are:

- Ownership of Reserves and Resources
- Geological Mapping
- Drilling Requirements
- Testing Requirements
- Regulatory Considerations
- Infrastructure and Market
- Time of Production and Development
- Economic Factors
- Forecast Prices and Costs
- Reserve Estimation Methods

For non-conventional reserves and resources, additional volumes of COGEH are being prepared.

(6) Should the Commission reconsider the concept of reasonable certainty?

This topic has been discussed in Question 4. Definitions based on Statistical Concepts are much superior to Word Descriptions. A word may have a very different meaning to various individuals, with differing stakes in the oil and gas industry, resulting in a lot leeway in estimating reserves. However, Statistical Concepts imply a very explicit meaning which should standardize reserves estimates, and therefore they should be employed in the evaluation process.

(7) Should the Commission reconsider the concept of certainty of proved undeveloped reserves?

As noted in Question 4, Undeveloped Reserves, whether they be in the Proved, Probable, or Possible categories, will have the same criteria as the major reserve categories, P_V, P_B or P_S . In Canada, companies can book P_VUD, P_BUD, and P_SUD reserves as long as they satisfy the respective confidence levels of each major reserves category. Since Undeveloped Reserves are non-producing, there is the possibility that these reserves could remain on the company's books for long periods of time before they are tested and put on production. NI 51-101 requires an annual running tabulation of the undeveloped reserves to keep track of the company's endeavours to develop these reserves. If they are not developed within a reasonable period of time, the company may be requested to remove these reserves from the disclosure or provide compelling reasons for the delay.

(8) Should the Commission reconsider the concept of economic producibility?

In every reserves classification system, hydrocarbons have to be economic to produce (future revenue exceeds expenses) to be classified as reserves. If they are not economic, they will be classified as resources. Evaluations prepared for internal company operations are based on forecast prices and costs. In each cash flow forecast of an entity, an economic limit will be determined at which time the production forecast will be truncated. The sum of the production to this date constitutes the reserves.

(9) Should the Commission reconsider the concept of existing operating conditions?

In answer to this question, it is assumed that "existing operating conditions" refers to no cost inflation for operating expenses. Similar to Question 8, operating costs must also be inflated in the future. Also, new unproven technology advances should not be considered in an evaluation.

(10) Should the Commission reconsider using sale prices in estimating reserves?

The first consideration in this question is that the calculation of the volume of reserves of any hydrocarbon product is at the point of sale where ownership of the product changes. For oil, this is usually at the wellhead or at the terminal. For natural gas, the point of sale is that point downstream from a processing plant where the residue (sales) gas is purchased by a transmission company who delivers the residue gas to consumers.

In some instances, natural gas is sold in an unprocessed state or as raw gas. In this case, the natural gas price will reflect the content of the raw gas mixture and Raw Gas Reserves will be reported.

In Canada, where companies are producing bitumen, they often refine the bitumen and produce Synthetic Oil. In cases where companies do not process their bitumen production but sell it to refining companies, they will estimate and report Bitumen Reserves. Companies that refine their production should estimate and report Synthetic Oil Reserves plus other products that may result from the refining process. Further, it should not make any difference whether the bitumen is produced from Insitu techniques or from Mining operations, they all should be included in oil and gas activities.

All evaluations, in Canada, are primarily based on Forecast Prices and Costs. Other price scenarios can be considered after the primary case is completed. The need to provide constant price evaluations is no longer a requirement in Canada. Each evaluation firm and oil and gas company prepares their own forecast of prices and costs. It is important to understand that, although the price forecasts are predictions of the future, they need to comply with the price forecast that is being used in the industry to set value of reserves, as of the effective date of the evaluation. Evaluation firms, oil and gas companies and financial analysts must also do a lot of detective work to establish what is the average price forecast being used in the industry. They must investigate recent sales and purchases of oil and gas assets and also try to establish whether the base evaluation was realistic, conservative, or optimistic which will dictate the price forecast used in the transaction. A conservative evaluation will require an optimistic price forecast, whereas, an optimistic evaluation will require a conservative price forecast. Evaluators must be conscientious at all times when preparing an evaluation, using their own forecasts of prices and costs, that the evaluation is realistic and satisfies the criteria of "Fair Market Value".

The price forecasts must include prices for all saleable products. These price forecasts must be presented as part of the disclosure information.

Price sensitivities are not required since all qualified reserves evaluators and the investment community should be aware of what prices are being used in the industry. One only needs to request pricing information from independent evaluators who often publish their current forecasts on their website.

Banker's price forecasts should not be used in evaluating reserves under Fair Market Value criteria. These prices are used for lending purposes, and if the evaluation is to be used for this purpose, then a price sensitivity case would be necessary.

Hopefully, stakeholders in the industry realize that price forecasts are only estimates as of a particular date and that they will change as perceptions of the future fluctuate.

Included with forecasting prices, cost inflation factors are routinely determined and reported with their price forecasts.

(11) Should the Commission eliminate any of the current exclusions from proved reserves?

Hydrocarbon volumes that are produced and sold, under any conditions, should be estimated and reported as reserves. This includes conventional methods and non-conventional methods such as coalbed methane, bitumen, whether insitu or from mining operations, and from gas shales plus other recoveries that are being considered. Hopefully, these products are contributing to a company's positive net revenue stream.

Currently, some of the SEC's exclusions divide hydrocarbons between conventional oil and gas activities and mining operations. Each has different definitions and evaluation rules resulting in different values for similar products produced under differing conditions. Mining tar sands to recover bitumen should be included in oil and gas activities. More on this topic later.

(12) Should the Commission consider eliminating any of the current exclusions from oil and gas activities?

The answer to this question is the same as for Question 11. Basically, if hydrocarbons can be produced from any operations, they should be included in Oil and Gas Activities.

The Commission currently excludes reserves when the company does not have the Funds or the Ability to Raise Capital to develop these reserves. This exclusion must be removed in new rules, if the intent is to follow the "Full" disclosure philosophy. Funding is not a consideration of the evaluator because whether funding is available or not these undeveloped reserves have the same Fair Market Value. If a company is in this rather poor financial position it should farmout or sell it's interests in these reserves.

(13) Should the Commission consider eliminating current restrictions on including oil and gas reserves that require further processing, e.g., tar sands?

The Commission should remove restrictions on reserves that need further processing. The following are classic examples of two situations where one is included and one is excluded:

(a) Included

The production of sour wet raw gas containing natural gas liquids, acid gas (H_2S and CO_2) and non-inert gases, is usually processed through complex gas plants which separates the raw gas stream into residue (sales) gas, natural gas liquids (C_2, $C_{3,}$ C_4, C_5^+), and sulphur and also removes the non-inert gases. Currently all of these products can be assigned reserves even though a lot of processing has occurred.

(b) Excluded

Bitumen, whether produced from insitu processes or mining operations, needs to be processed to render this tar-like substance into useable products or reserves. Usually, Synthetic Oil along with some other hydrocarbon products are produced. These products should not be treated any differently from those products produced from a gas plant. As noted in Question 10, if bitumen is sold before processing, this product will be classified as Bitumen Reserves, however, if it is processed and synthetic oil is sold then the company should be able to book Synthetic Oil Reserves. Currently, however, synthetic oil reserves cannot be booked under SEC rules because it is a product of a refining process.

The inclusion of one case and the exclusion of the other does not seem reasonable in light of the purpose of "Full" disclosure.

(14) What aspects of technology should the Commission consider in evaluating a disclosure framework?

Only current technology and any new technology that is in the final experimental stages and likely to be a commercial process in the near future should be considered for disclosure purposes. Reserves and Contingent Resources will categorize recoveries from existing technologies, whereas Prospective Resources alone will categorize recoveries expected from new technologies that are on the verge of a major breakthrough from new recovery techniques.

Other new technologies that are in the early experimental stages will undoubtedly have a significant amount of uncertainty associated with them and will therefore constitute very little value to an oil and gas company. They are, however, very valuable to research and development teams, but until they are proven, they should not be considered in public disclosure of reserves and resources, but rather, their significance should be presented in management's discussion on the activities of the company.

(15) Should the Commission consider requiring companies to engage independent qualified reserves evaluators to evaluate their reserves?

Given that oil and gas reserves are among the most significant assets of an oil and gas company, evaluations must be prepared by Qualified Reserves Evaluators whether the evaluation is performed by an Independent Evaluation Firm or done internally by the company's own Qualified Reserves Evaluators. If done by an independent firm, there is no need to perform a subsequent audit of the evaluation, however, if the evaluation is prepared internally, an Independent Audit should be undertaken by Qualified Reserves Auditors. COGEH Volume 1 outlines the qualifications for Qualified Reserves Evaluators and Qualified Reserves Auditors.

Financial statements of companies have to be independently audited whether the statements have been prepared independently or internally. Given the importance of an evaluation of reserves and resources, they too should demand the same degree of scrutiny.

The data to be extracted from the evaluation report and disclosed in Form NI 51-101 F1 "Statement of Reserves and Other Oil and Gas Information" should be prepared by qualified reserves evaluators. Further, a second report, Form NI 51-101 F2 "Report on Reserve Data" must also be prepared by the Qualified Reserves Evaluator, either independently or internally, and/or by the Independent Auditor indicating that they evaluated or audited the evaluation report from which the information was obtained to prepare Form NI 51-101 F1. The report must be signed by the Independent Evaluation Firm or by the internal Qualified Reserves Evaluator and Independent Auditor.

A third report, Form NI 51-101 F3 "Report of Management and Directors on Oil and Gas Disclosure", indicates that Management of the Company is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities. Signatures are required by the Chief Executive Officer, a Senior Officer other than the Chief Executive Officer, and by two company Directors.

In Canada, a reporting issuer shall file Form NI 51-101 F1, Form NI 51-101 F2 and Form NI 51-101 F3 with the securities regulatory authority not later than the date required by securities legislation.

Reporting Reserves

Oil and gas and related products reserves must be reported as distinct and separate products. They should not be aggregated such as adding natural gas liquids to light and medium oil or adding heavy oil to light and medium oil. The following table lists the common oil and gas products and also illustrates an important practice of grouping products into Production Groups:

Conventional Production Groups	Major Product	Minor Products
Light and Medium Oil	Light and Medium Oil	Solution Gas Natural Gas Liquids (from Solution Gas) Sulphur (from Solution Gas)
Heavy Oil	Heavy Oil	Solution Gas (occasionally) Natural Gas Liquids (occasionally)
Associated and Non – Associated Natural Gas	Natural Gas	Natural Gas Liquids Sulphur Other Non- Hydrocarbons

Non- Conventional Production Groups	Major Product	Minor Products
Coalbed Methane	Natural Gas	-
Shale Gas	Natural Gas	-
Tar Sands	Bitumen	Bitumen Synthetic Oil
Hydrates	Natural Gas	-

The importance of summarizing the evaluation results into Production Groups cannot be stressed enough. It basically summarizes the reserves and NPV's by the different major product groups which is akin to establishing Task Forces in an organization to ascertain the accountability and productivity of each group. The summary of a production group can be a quick indicator to identify errors in an evaluation. Evaluators can calculate the Unit Values of each major product reserves which should fall within acceptable ranges, and if not, the evaluation should be reviewed for possible errors. The summaries are also a very convenient means of determining Value Equilivant BOE's which will be discussed later.

Reserves should be reported for both Company Working Interest Reserves and for Company Net Interest Reserves (after royalties) for each product type and reserves category. Details of ownership issues are pesented in the COGEH.

Reporting Net Present Value (NPV) of Future Net Revenue (FNR)

The NPV of FNR should be reported for at least five discount rates and for both before and after income taxes. A lot of evaluators are reluctant to include income taxes in their evaluations, however, income taxes are the largest expense of an oil and gas company. To ignore taxes is a large shortcoming and once again "Full" disclosure is not being provided. Prior tax pools should be included in the cash flow tax calculation. Remember that an evaluation is a forecast of a run-down scenario and thus the income tax calculation may be different than that performed by an accountant. Also the term "Net" in FNR means net of everything including income taxes.

Refer to NI 51-101 Companion Policy NI 51-101 CP for recommended tables for presenting reserves and NPV of FNR.

Statistical Concepts

At the first sound of the terms, "Statistical and Probabilistic Concepts", a lot of stakeholders in the oil and gas industry turn a deaf ear and hope that this notion will pass. Unfortuately, for such individuals, these concepts are not going away. The acceptance of these concepts is slowly making advances, and are going to play a major role in the evaluation process in the future. They will eliminate a lot of unnecessary problems, some of which are discussed in this document.

Although formal rigorous statistical procedures are seldom used, oil and gas reserves and resources evaluations are based on statistical and probabilistic concepts. All the factors in projecting future cash flow have some degree of uncertainty and thus have to be dealt with. A basic understanding of these concepts and the associated terminology is essential in preparing and using evaluations. As noted in

Question 4, the majority of evaluators are reluctant to place confidence levels at the Entity Level. The main reasons for this reluctance are:

(a) Emphasis on Proved Reserves

Since there is so much emphasis placed on Proved Reserves in the financial community, rather than on Proved plus Probable Reserves (P_{50}), evaluators are constantly being coerced into increasing their arithmetically aggregated proved reserves estimates. To keep their clients happy, evaluators relax the criteria for the proved reserves at the entity level, yet still hoping to meet the P_{90} confidence level at the total company level. For companies with a large number of entities this procedure may be tolerated, but it is a rather poor solution to not assigning explicit confidence levels at the entity levels thus preventing the use of simple probabilistic aggregation. The procedure of relaxing the criteria at the entity level becomes further complicated when the evaluator has to evaluate the same entity for other smaller companies. Where the larger proved reserves estimates worked for the large company and hopefully met the total P_{90} confidence level, they probably would not work for a smaller company. Evaluators are in a dilemma, because, giving the small company a smaller proved reserves will result in "evaluation disaster" – why should they receive a lower reserves estimate than the large company? The industry has to move away from the conservative proved estimates (if they really are conservative?) towards the Proved plus Probable Reserves (2P or P_{50}) estimates which is that used in industry for making business decisions.

(b) Arithmetic and Probabilistic Aggregation

Arithmetic aggregation of 1P, 2P and 3P reserves estimates is the only method that is currently permitted worldwide including Canada. This is the root of the problem described in (a) above. If fixed confidence levels were also established at the entity level for the 1P, 2P and 3P reserves estimates such as P_{90}, P_{50} and P_{10} or some other equivalent confidence levels, and probabilistic aggregation was allowed, the problem of aggregation of 1P and 3P reserves would be solved. Aggregation of 2P reserves is the same regardless of which method is used. Probabilistic aggregation is a very simple calculation once standard confidence levels are fixed at the entity level for 1P, 2P and 3P reserves estimates. The three values of reserves define a distribution curve, which can be used in a statistical calculation to determine the probabilistic aggregation. Because of the portfolio effect, companies with a large number of entities would have probabilistic aggregated 1P and 3P reserves very close to their 2P estimates. Companies with smaller number of entities would have a wider spread between their 1P and 3P reserves. Exactly what should happen.

Deterministic and Probabilistic Methods

Reserve estimates may be prepared using either deterministic or probabilistic methods.The Deterministic method is by far the most common procedure and will continue to be the forerunner in the future. Probabilistic methods will be reserved for the highly uncertain, high reward projects.

Deterministic reserve estimates use single input values to provide a single answer. The input and output values are all part of a specific value in a range of possible values. Probabilistic reserve estimates is a procedure which uses distribution curves for each parameter and through simulation, such as the Monte Carlo Method, a distribution curve for the answer will be calculated. The Probabilistic method will provide statistical measurements of central tendency such as the Mode (most likely), the Median (P_{50}), and the Mean (expected value, arithmetic average, best estimate). Statistical measurements of the dispersion of data such as Minimum and Maximum values and various confidence levels (P_{90}, P_{50}, P_{10}) will also be determined.

The author would like to point out that the P_{50} value is not the most appropriate value to be used in the evaluation process. As noted previously, it reprsents the Median value. If we want to express the best estimate or the expected value, which is used in other scientific disciplines, we should be using the Mean. It is not known when and why the Median P_{50} was selected, but, as with many other ill-conceived plans, it might be here to stay.

However, it must be stressed that deterministic and probabilistic methods are not separate and distinct. Whether probabilistic or deterministic methods are used and, within the limitations of the data and in the absence of bias, reserves estimates derived from one of the methods should not be significantly different from those derived from the other. For example, suppose an estimate is made for proved reserves using a deterministic method that targetted a P_{90} confidence level. The answer should be equivalent to a probabilistic P_{90} estimate. If the answers are materially different, then one or both sets of data used in each estimate are not coherent or the methods are being applied incorrectly.

A note of caution here: probabilistic multiplication and aggregation may be the culprit in comparing reserves estimates between methods. It is recommended that reference be made to the COGEH or other statistical documents to understand the effects of probabilistic multiplication and aggregation.

Monitoring Oil and Gas Reserves Evaluation

Reserves Reconciliation is an important procedure in monitoring oil and gas reserves evaluations. In Canada, a reserves reconciliation is undertaken at least annually to analyse the flow of reserves into and out of companies reserves base between the previous and current year's reserves estimates. The reconciliation only needs to be prepared for the major product of each production group since a reconciliation of the minor products within a group will follow the same trend as was calculated for the major product. The reserves categories that should be analysed is the Proved (P_v), Probable (P_B) and Proved + Probable (2P) Reserves. Other categories can be included, but not required. The major products, as presented previously are:

Conventional Reserves
- light and medium oil
- heavy oil
- natural gas

Non-Conventional Reserves
- bitumen
- synthetic oil
- coalbed methane
- shale gas
- hydrates, etc.

The categories used in NI 51-101 for the Reserves Reconciliation are:

- Opening Balance
- Exploration Discoveries
- Drilling Extensions
- Infill Drilling
- Improved Recovery
- Technical Revisions

- Acquisitions
- Dispositions
- Economic Factors
- Production
- Closing Balance

Reference should be made to the COHEH and NI 51-101 for guidelines for each category. Since the Technical Revisions is such an important category in monitoring the performance of an evaluator, a few comments will be provided. Technical revisions apply only to those properties that are carry-forwards from one year to the next. This reconciliation indicates how the estimates of reserves are standing up to the test of time. There will be positive and negative revisions, however, the accepted targets for technical revisions at the entity and total levels are:

Reserves Category	Entity Level	Total Level
1P	Positive reserves revisions should occur in significantly more of the entities than negative revisions.	Negative reserves revisions should seldom occur at this level.
2P	Positive reserves revisions should equal negative reserves revisions.	Only minor positive or minor negative revisions should occur at this level.
3P	Negative reserves revisions should occur in significantly more of the entities than positive revisions.	Positive reserves revisions should seldom occur at this level.

Reserves additions requiring capital expenditure such as Infill Drilling must not be included in Technical Revisions.

The process of validation of the reserves estimates could take several years and, therefore, a Production Reconciliation should also be undertaken. Comparing Production Forecasts of a previous year's evaluation with Actual Production will instantly indicate if the evaluator is making realistic projections of production of the reserves in accordance with the particular reserves category. The 2P forecast should be tracking the actual production, whereas the 1P forecast should be less than the actual production and the 3P forecast should be greater than the actual production. If an evaluator can't make realistic projections for the next year how can confidence be placed on projections made for many years in the future?

Reconciliation of Net Present Value (NPV) of Future Net Revenue (FNR) has been currently eliminated for disclosure requirements in Canada. This reconciliation is a valuable tool but under current procedures it is extremely difficult to calculate and there is much doubt about the quality of the values presented. The author is suggesting a revised procedure that will use only the evaluation data and eliminate all the actual accounting values to streamline the calculation. The reconciliation between the previous year's evaluation and the current year's evaluation can be done using the economic model to calculate the differences between respective cases. This calculation will be much easier to perform and will provide all of the important reasons why the NPV of FNR has changed from one year to the next.

Resources

The majority of the comments, thus far, are about estimating and reporting oil and gas reserves. With the maturing and the depletion of conventional oil and gas reserves, companies are forced to turn to frontier areas and non-conventional sources to find new oil and gas deposits. New technologies, such as 3-D and 4-D seismic, provide more direction for exploring for new reservoirs. Computers and Software Programmes are also improving the ability of companies to find new reservoirs and also to enhance production from existing fields. Great strides have been taken to enhance the production of bitumen from Canada's Tar Sands, either by insitu or mining operations and likewise with coalbed methane. Projects in frontier areas with high uncertainties are also being evaluated. All of these operations have been prompted by the decline in conventional reserves and by the increasing oil and gas prices.

In the inititial stages of these projects, usually reserves cannot be booked and thus the term Resources has been incorporated. The definitions pertaining to Resources is contained within the definitions of Resources and Reserves presented in the COGEH and as referenced in Question 4 above. There are two major categories of Resources which can be summarized as follows:

(a) Contingent Resources:

These are quantities of petroleum products estimated, as of a given date, to be potentially recoverable from Know Accumulations using established technology or new technologies under development. These resources are currently not considered to be commercially recoverable due to one or more contingencies including such factors as economic, legal, environmental, political, and regulatory matters, or a lack of markets.

(b) Prospective Resources:

These are quantities of petroleum products estimated, as of a given date, to be potentially recoverable from Undiscovered Accumulations. They are considered to be technically viable and economic to recover.

Contingent and Prospective Resources, like reserves, can be sub-classified into Low, Best and High Estimates to better define the confidence levels of these resources. The procedure is similar to categorizing reserves into 1P, 2P and 3P reserves. The basic definitions as published in COGEH are:

- Low Estimate: a conservative estimate of the quantity that will be recovered.
- Best Estimate: a best estimate of the quantity that will be recovered
- High Estimate: an optimistic estimate of the quantity that will be recovered

Similar to the 1P, 2P, and 3P reserves estimates, the Low, Best and High Estimates of resources are not unique and not mutually exclusive. They are all part of an estimate and are presented to illustrate the uncertainty about the Best Estimate.

The most relevant way to evaluate Contingent and Prospective Resources is to use the same techniques as used to evaluate reserves (the discounted cash flow method) but involves another step to account for the uncertainty in the geology and engineering data used in the evaluation process. The most commonly used probabilistic methods are the Expected Value and Decision Tree Methods. They are simple to use and understand and have been a mainstay in the industry since the first discovery of petroleum. Monte

Carlo simulation methods are also used, but because of the complexity of the technique and the additional expense involved, they are usually restricted to high-risk, high-reward projects.

It is important to note that just because some projects do not have reserves assigned to them, it doesn't mean that they do not have value. In fact, some contingent and prospective resources have significant value and must not be ignored in valuing an oil and gas company. Some emerging companies may have the majority of their value in Contingent and Prospective Resources.

The mandatory inclusion of resources in a company's annual disclosure is a somewhat contentious issue among oil and gas companies. For some companies, disclosure of their resources would not be in the best interest of the company, especially if the information is proprietary and highly confidential. However, the Commission must develop guidelines in the event that companies do want to report their contingent and prospective resources. If a company with very valuable resources does not want to disclose this type of information, it can apply for an exemption, and if the exemption is approved, the management and company staff, who are aware of the extent of the exclusion, will be required to cease trading in their securities until such time as the confidential information becomes available to the public.

Risk and Uncertainty

The use of the terms Risk and Uncertainty are often interchanged incorrectly. The Oxford dictionary describes the two terms as follows:

Risk:	expose to the chance of injury or loss
Uncertainty:	not known or not knowing certainty

In years past, evaluations were prepared for the most optimistic case and then reduced by an appropriate risk factor to arrive at an expected outcome. Currently, with the designation of 1P, 2P, and 3P reserves estimates, the expected outcome is reflected by the 2P estimate with the 1P and 3P estimates providing the sensitivity of the uncertainty about the 2P value. Large differences between the 1P and 3P reserves indicates a high degree of uncertainty whereas small differences mean a low degree of uncertainty. The focus today is to use the terms Certainty and Uncertainty and not use the term Risk.

Consistent Use of Units of Measurement

One of the prime objectives of a good disclosure system is to assure that consistencies prevail not only between companies but also within a company's own disclosure documents. Consistency not only applies to the data that is published but also to the Units of Measurements. It is a simple procedure if individuals would take the time to apply Universal Standards. As expected, standards differ from country to country. The standards, that apply in North America and in a lot of other political regions involved in producing oil and gas, are presented in Appendix B and C of the COGEH Volume 1. In Canada, the International System of Units (SI or Metric) has become the official standard, but still, most of reserves and resources information is presented in the Imperial System of Units, which is also also used in the United States. One mistake that is often made is the use of SI Prefixes with Imperial Units and vice versa. The prefixes are not interchangeable. The following table provides a comparison between Imperial and SI Prefixes and also Traditional British Names:

Term	Imperial Prefix and Magnitude	SI Prefix and Magnitude	Traditional British Names
Thousand	M(10^3)	k(10^3)	
Million	MM(10^6)	M(10^6)	Million(10^6)
Billion	B(10^9)	T(10^{12})	Milliard(10^9)
Trillion	T(10^{12})	E(10^{18})	Billion(10^{12})

Please don't harm the messenger, he didn't make the rules. But if either the Imperial or SI Units of Measurements are used consistently all will be well. Also, putting a band-aide on the problem by listing your own units of measurements in a report does not solve the problem. Some common errors that the author has witnessed are:

(a) The correct Imperial units for expressing millions of cubic feet of gas is "MMcf". What often is used is:

- mmcf: this means - micro micro cubic feet, a lot smaller than MMcf ??
- Mmcf: this means – thousands of micro cubic feet, not gaining much ground??

(b) The prefix for billion is "B". The correct unit of measurement for a barrel of oil is "bbl". What often is used is:

- Bbl: this means – Billion bl, whatever a bl is??

(c) Care must be taken when applying a prefix from one system in conjunction with a unit of measurement from the other. An example of a misuse was observed when a reporting issuer stated that the land holdings of his company were:

- 6.7 MM hectares of land: which is 6.7 x 10^{12} hectares or 6.7 billion hectares, bigger than the surface of the earth??
- What the reporting issuer meant to report was 6.7 million hectares or 6.7 M hectares which is quite a bit smaller. The prefix for million in the SI system is "M'.
- When using a SI unit of measurement, you also must use the SI prefix.

Revising the Disclosure Requirements Relating To Oil and Gas Reserves

The following comments are included as suggestions of what professional group or groups should be involved in the revision and/or development of the Guidelines and Procedures of Evaluation Oil and Gas Reserves (Reserve Guidelines) and of the U.S. Securities and Exchange Commission's Oil and Gas Reserves Disclosure Requirements (Disclosure Requirements). These recommendations are based on the author's experience in evaluating oil and gas reserves and resources, spearheading the development of COGEH, co-authoring the writing of NI 51-101 and assisting several companies in the preparation of their annual NI 51-101 statements.

Before getting into the specifics, it is highly recommended that all Reserves Guidelines and Disclosure Requirements that are currently in existence worldwide be utilized to their utmost. This would include, but not limited to, the current documents developed by the Commission, the COGEH and NI 51-101 developed in Canada and the SPE-PRMS system. I trust that one of the main objects of the Commission and of other Securities Regulators throughout the world, would be to move towards “Standardization of Reserves Guidelines and Disclosure Requirements and Rules”. Also, as emphasized throughtout this document, “True, Full and Plain” disclosure philosophy must be an overriding principle in the new disclosure requirements and rules.

(a) Reserve Guidelines

Throughout this document, the COGEH has been continually referenced as an excellent source for the guidelines of evaluating oil and gas reserves. This document was totally developed by Qualified Reserves Evaluators, comprised of Professional Engineers and Geologists. These professionals were not constrained by any other discipline. The document is based on sound principles of geophysics, geology, petrophysics and engineering. The result is a very comprehensive document on how to prepare an evaluation of oil and gas reserves and resources that can be used for any purpose and by any stakeholder in the oil and gas industry. It is hoped that there are no biases towards any one guideline or practice and any one purpose or use within the oil and gas industry.

Development of the COGEH was undertaken coincidentally with the development of NI 51-101. COGEH Volume 1 was published on June 30, 2002. COGEH Volume 2 was published on November 1, 2005 and additional volumes are currently being developed.

(b) Disclosure Requirements

The first step in the development of the Canadian NI 51-101 began from recommendations made from an ASC Oil and Gas Securities Taskforce. The Taskforce, established in 1998, was comprised of a panel of 27 professionals drawn from oil and gas issuers, reserves evaluators, oil and gas accountants, securities lawyers, investment dealers, the Canadian Venture Exchange, and the ASC. The Taskforce recommendations were received by the ASC in 2001 after which the information was assembled and organized into specific topics. Comments were also solicited from the public.

A first draft was prepared by a team of lawyers and qualified reserves evaluators, including the author, with occasional input from accountants. Throughout NI 51-101, frequent references were made to the COGEH when specific oil and gas reserves and resources information was included in the disclosure rules. This procedure eliminated the need to provide details of oil and gas evaluation terminology and principles in NI 51-101. The first draft was published for comments, and after receiving and analysing the many critiques, a final version of NI 51-101 was prepared. The new rules came into effect on September 10, 2003.

The development of NI 51-101 took approximately five years from the date of the establishment of the Taskforce to the effective date of the new NI 51-101. A lengthy period of time is required to deal with the public concerns and, at the same time, establish a set of regulations and rules that will endure the “test of time”.

The resulting NI 51-101 disclosure rules and regulations satisfy both the legal requirements and the evaluation standards set out in the COGEH.

(c) Accounting and Evaluations of Oil and Gas Reserves and Resources

As stated in the Concept Release document, oil and gas reserves and resources information do not appear on a company’s balance sheet, however, “it is one the most significant assets of an oil and gas company”. Full consideration must be given to this statement. Oil and gas evaluations do not follow accounting rules. They are estimates of the future production of the companies reserves and resources with corresponding projections of future revenue and expenses. These annual projections are referred to as “Cash Flows” in the evaluation business. Basically, “evaluation cash flows are projections of the movement of money into and out of the treasury of a company”. It is that simple, no more or no less.

The importance of a company’s evaluation of oil and gas reserves and resources is exemplified, in Canada, by the inclusion of FORM NI 51-101 F1 in their annual information form. The information presented in this form is the company’s “Statement of Reserves Data and Other Oil and Gas Information” which is taken directly from the Evaluation of the Company’s Oil and Gas Reserves and Resources Report. The data is unabridged and is sufficently comprehensive to allow a knowledgeable stakeholder in the oil and gas industry to estimate the value of a company’s oil and gas reserves and resources and it’s current operations.

Accounting Rules and Uses of Evaluation of Oil and Gas Reserves and Resources Data

Coincidentally, with the development of Reserves Guidelines and Disclosure Rules, accountants should take advantage of this opportune time to review their oil and gas rules and principles. There are some accounting practices and economic indices which utilize oil and gas evaluation data, but in doing so, create concerns with the reserves and resources evaluators. There are simple solutions to these problems which will create more easily understood and more compehensive information to be used by the public and investment community. A few of these concerns are:

(a) Finding and Development Costs (F&D Costs)

This index, as it is used today, is calculated by taking the yearly capital spent divided by the proved reserves additions for the most recent fiscal year. A better definition of this method of calculation is a “Return on Capital Employed”. A true F&D Cost calculation includes all sunk capital and future capital that is required to find and develop the reserves, divided by the total historical product and the remaining 2P reserves that will be ultimately be recovered from the discovery. This number is seldom presented in a company’s disclosure. It is a good tool for management to compare the performance of their exploration and development team to find and develop reserves against purchasing equilivant reserves in the market place.

As it is now used, problems arise for management when reserves are booked in a year before a significant amount of the development capital is spent. The F&D Cost for this year would be extremely low – lots of reserves with little capital. In subsequent years, when the development capital is being spent with little or no reserves additions the F&D Costs would be dismally high – lots of capital with little reserves additions. Consequently, evaluators are faced with the problem that companies do not want to book undeveloped reserves until such time as all the capital is spent, so they can “Manage their F&D Costs”. Further, this exclusion would deviate from the “Full” disclosure concept. Also in this case, if management and the employees of a company made transactions in the securities of their company, while having knowledge of reserves that were booked and not disclosed to the public, insider trading investigations would be triggered.

There is a viable alternative to the F&D Costs indice. It is defined as the “Discounted Return on Investment” (DROI) or also called the “Discounted Profit to Investment Ratio” (DPIR). Basically, the ratio is the incremental increase in NPV divided by the amount of the Investment or as simply stated, how much has the value of the company increased per dollar of investment. Reserves do not enter into the calculation so projects that don’t add reserves are as equally important as those that do add reserves.

(b) Barrels of Oil Equivalent (BOE)

There are situations where it is convenient to convert non-oil products into BOE's. The current practice of using an Energy Equivalency is only applicable at the burner-tip. For accounting depletion calculations, energy equivalency is perhaps satisfactory to use because the same BOE ratio is used in both the numerator and the denominator of the equation and thus should cancel out any inappropriateness. Most other needs for the use of BOE conversion pertains to a Value Equilavalency. A Value Equilavalency is simply the ratio of the unit value of one product divided by the unit value of a second product. Herein lies one of the important reasons for grouping minor products within respective major production groups. From these production groups, the unit value of a major product can be calculated from the total groups NPV, at a select discount rate, divided by the net reserves of the major product. The discount rate should be that used in the industry for setting the value of oil and gas reserves. Ratios of respective major products provides the Value Equivalency BOE between these products. For example, suppose a company's unit value of light and medium oil is $55.00 per bbl and the unit value of associated and non-associated gas is $6.00 per Mcf, the Energy Equivance BOE between the oil and gas is 9.17 ($55 / $6) Mcf/bbl. If the unit value of the company's heavy oil is $35.00 per bbl then the Energy Equivalence BOE between the light and medium oil and the heavy oil is 1.57 ($55 / $35) bbl/bbl. Simply stated, if you had $55.00 in your pocket you could buy 1 bbl of light and medium oil or 9.17 Mcf's of associated and non-associated gas or 1.57 bbl's of heavy oil.

(c) Netback Calculation

The traditional Netback calculation starts with the unit price of a particular product from which the unit costs of royalties, expenses, income taxes, etc. are deducted to determine how much of the unit price is left for profit. It is a simple calculation but has it's drawbacks. Since evaluations are performed at the production group level where all the expenses are lumped in with the major product expenses, it becomes difficult or impossible to break out the expenses for each individual product type. A much simpler method would be to start with a company's total gross revenue and then deduct the royalities, expenses, income taxes, etc., to determine the net profit. Further, each deduction can be represented as a percentage of the 100 percent gross revenue and what percentage is left is the profit. This procedure is a much simpler calculation and provides a better analysis of where the money goes.

(d) Property, Plant and Equipment

Currently, historical costs are reported as "Property, Plant and Equipment" (PP&E) in a company's balance sheet to represent the value of the company's upstream oil and gas assets. However, seldom do historical costs reflect the value of oil and gas reserves and resources to be produced in the future. A much perferred entry in the balance sheet would be the "Fair Market Value" of the reserves and resources which can be easily derived from an evaluation report. It can be calculated from the NPV of the FNR of the Proved plus Probable (2P) Reserves and of the Best Estimates of the Resources, both calculated using forecast prices and costs. The discount rate that should be used to determine the appropriate NPV is that rate used in the industry to set the value of oil and gas reserves and resources in the market place. All qualified reserves and resources evaluators must be knowledgeable in the values of these assets because their evaluations must meet the criteria of Fair Market Value. A few other indicies need to be considered to estimate Fair Market Value, but overall, the calculation is not onerous. Fair Market Value included in the balance sheet will alleviate the need to perform ceiling tests. This approach will utilize a value that will inevitabily fluctulate over time but that is a fact of life.

Benefits and Cost Efficiencies

Should the new SEC Disclosure Rules follow the comments and recommendations presented in this document, there will be significant Benefits and Cost Efficiencies for the investors, issuers and the Commission.

(a) Investors

Investors and other stakeholders involved in the oil and gas industry will experience a significant benefit from using the new Value Concept disclosure rules. The quantity and quality of the reserves and resources data will greatly enhance the analysis of the performance of oil and gas companies by alleviating the need to do a lot of additonal research into a company's reserves and operations.

(b) Issuers

Issuers will no longer need to keep two sets of reserves data – one for securities' filings and one for making internal business decisions. Also, the disclosure data can be taken directly from their evaluation report. No need to prepare additional forms and data. With the new comprehensive disclosure information, companies can now keep better tabs on their competitors and obviously vice versa.

(c) Commission

Under the Principles-Based Rules, the rules should be prepared by Qualified Reserves Evaluators who will base their guidelines on sound engineering and geological practice. The oil and gas department at the commission will no longer have to reply to "what if questions". They can refer these queries back to the organization that develops the reserves and resources estimation guidelines. Furthermore, if the disclosure requirements and rules are developed by the appropriate mix of professionals, including qualified reserves and resources evaluators, there should not be any rules developed that would be unacceptable to different disciplines.

Obviously there a short learning curve will be required, but the benefits from the new system will greatly outweight the efforts to learn the new disclosure rules. The oil and gas industry are anxiously waiting on the new rules.

Other Comments

Before concluding this report there are a couple of other comments that need to be included.

(a) Evaluation is a Science

The evaluation of oil and gas reserves and resources is not an Art but is truely a "Scientific Procedure" using sound geophysical, geological, petrophysical and engineering principles enhanced with some basic economic fundamentals.

(b) Evaluation Report

A report presenting the results of an evaluation of oil and reserves and resources must not be referred to as an "Engineering Report". All disciplines as noted above are expected, to the extent required, to contribute to the preparation of the evaluation. The report must be referred to as an "Evaluation Report". Furthermore, the report must be comprised of factual geophysical, geological, petrophysical, engineering and economic documents. In Canada, the report must be prepared by or under the direct supervision of a registered professional who is a qualified reserves evaluator and is a member in good standing of APEGGA. The report must be signed by each registered professional who accepts responsibily for the specific contributions that they either prepared or that was prepared under their direct supervision.

Conclusions

The majority of the material presented is already in summary form and thus no formal conclusions are presented.

However, in concluding this report, the author would like to wish the U.S. Securities and Exchange Commission staff all the best in their endeavours of ”Possibly Revising the Disclosure Requirements Relating to Oil and Gas Reserves”. I hope some, if not all, of the information presented will assist in the project. As always, I welcome the opportunity to further discuss any aspects of the information presented herein or any other topics pertaining to evaluating and disclosing oil and gas reserves and resources. Please be advised that I am available to assist your staff in this development in any way whatsoever, for which I am qualified.

Yours Truly,
J. Glenn Robinson, P. Eng.