

## Responsible Reporting of Uncertain Petroleum Reserves

Mark McLane, James Gouveia, Gary P. Citron, James MacKay and Peter R. Rose,  
Rose & Associates, LLP

Since exploration and production (E&P) efforts represent repeated trials involving many uncertain ventures, a statistical treatment of the associated undiscovered resources is appropriate. However, when we consider the required reporting of “Proved Reserves” after a specific discovery, we are currently required to specify a volume of hydrocarbons that we are “reasonably certain” will be economically recovered from wells associated with that discovery. The phrase “reasonably certain” is a probability statement, except that no confidence-level is specified by the governing authorities. Company appraisers may be influenced that larger estimates (if defensible) benefit the value of their company shares and perhaps their status within a company; while various negative consequences may ensue if actual outcome turns out to be smaller than the “reasonably certain” estimate. We view this clash of probabilistic methods versus determinism as an illogical professional conundrum. Since deterministic parameters are not probabilistically specified, a professional’s estimating ability cannot be properly measured and calibrated. Without a rigorous process for reality checking this approach encourages unrealistic thinking about uncertain resource values and thus can facilitate technical and financial unaccountability. In fact, ill-defined standards can actually encourage unethical behavior through confusion and manipulation, obscuring boundaries between professional objectivity and conflicting incentive systems.

The solution can be complex because of the many factors associated with uncertainty in subsurface parameters, product prices, government takes and capital costs; but it is also one that can be addressed by full disclosure. Plus the development of a unified standard within the E&P community of probabilistic reserve definitions for “Proved”, “Probable” and “Possible” reserves. Full disclosure of Probabilistic reserve estimates will:

1. Facilitate reality checking estimates against analogs and natural limits;
2. Help measure estimating accuracy against actual outcomes; and
3. Encourage improvements in future estimating accuracy and efficiency.
4. Provide transparency to the public.

Until there are more uniform standards developed and enforced, E&P entities will continue to use resource numbers beyond the “Proved” level as they are critically important for business planning and portfolio management of their shareholders assets.

## **Introduction:**

This paper addresses important issues linking assessment through estimation, analytical calculations and communication for future investment. Undeniably, this is a tall order, and accordingly, we seek to:

- 1) Build a better understanding of uncertainty in the assessment process of documenting what part of the discovered resources can be classified as reserves; and
- 2) Provide some clarity on the challenges that geoscientists, engineers and others, charged with the role of reserve reporting, face when deciding what portions of a resource base can be classified as either Proved (1P) or Probable (2P) in a formal company ledger available for external scrutiny or other categories for company planning.

Whether in an exploration mode preparing an opportunity for capital allocation, marketing this opportunity for placement and execution in someone else's portfolio, or documenting a developed opportunity to record the 1P and 2P amounts, there is clearly a business need for responsible reporting of the resources and reserves available.

In fact, the decisions we make (that is, any given field could be developed in a multitude of ways) and the subsequent activities we perform to monetize an opportunity could lead to different outcomes of production from a potential resource base. A firm's asset managers must constantly balance the desire to maximize the resource recovery with their shareholder's desire to maximize current revenues.

As a field matures, the amounts remaining and additions to the Proved category also need to be determined without bias, clearly recorded and communicated for planning purposes in any business enterprise that conducts multi-year planning efforts to achieve goals associated with their strategy.

With this premise, we address:

- i. The internal and external challenges to responsible reporting of petroleum reserves; whether they be prospective resources or reserves from established reservoirs eligible for booking as 1P or 2P;
- ii. The challenges that currently exist with the U.S. Securities and Exchange Commission's (SEC) current definition of "Proved" reserves, that includes the phrase "Reasonable Certainty";
- iii. The superiority of probabilistic methods relative to single-valued 'determinism' to provide more insight for better planning and business decisions; and
- iv. Some items to bridge these methods going forward.

At this point, it is important to distinguish between reserve quantification and reserve reporting. Reserve quantification involves the dynamic process of refining potential reserve estimates to reflect the decreasing uncertainty occurring as we acquire more information throughout the life of a reservoir. E&P companies quantify the reserves as a key component in their assessment of project's value. Reserve reporting refers to those amounts of hydrocarbons that can be specifically booked as reserves following the governing regulatory standards (e.g. SEC). Reserve quantification clearly lends itself to

probabilistic estimating; reserve reporting, while statutorily deterministic (i.e. a single number) for companies under the SEC's jurisdiction, can in fact be based on underlying probabilistic estimates. We note that other jurisdictions have embraced probabilistic reserve assessment.

Having a range of potential reserves allows for project economic valuation based on a number of development scenarios. Reserves booked as 1P or Proved and 2P or Probable, must meet a number of specific criteria, such as project capital sanctioning (typically occurring with project approval).

For a number of reasons, all oil and gas companies clearly want to legitimately add to their tally of 1P and 2P reserves. Investors will examine the 1P reserves as part, but not all, of their assessment of the value of any company. Further, companies want as large a 1P reserve base as allowable because it reduces their DD&A (depletion, depreciation and amortization) and externally reported F&D (finding & development) costs, both of which are used by analysts and investors to benchmark companies.

Let us review some key end users of our reserve estimates and what reserve number they would ideally like to see:

Simply put, **Accountants** have the desire to depreciate our capital investments equitably over the production life of our reservoirs. Ideally they would like to depreciate these capital assets equitably per each unit of value. Their current proxy for value is production. DD&A for the year is apportioned as an asset's annual production divided by their estimate of total future production from the asset (reserves). This method works well in an environment where there is no reserve, cost or price uncertainty. The current SEC rules which mandate the reporting of a single value for reserves, plus year end costs and pricing placate this desire. The use of 1P reserves will result in higher DD&A and will serve as a powerful motivator of booking bias as firms strive to deplete their investments as equitably as possible over future production.

Accountants are looking for our best estimate of reserves to get their DD&A as correct as possible. So what single point value is the best representation of reserves for DD&A purposes? Arguably it would be the P50 or median at the property level (where DD&A is calculated) and the mean at the corporate level. Accountants are not seeking an ultra conservative value which will result in a very low return on capital employed (ROCE) values early on and then escalating ROCE as a project matures and reserves are more frequently added. By definition the use of a P90 value for 1P would result in higher than desired DD&A being applied 90% of the time.

As Professor Eddie Riedl of the Harvard Business School advised attendees of the inaugural AAPG-SPE International Multidisciplinary Reserves Conference held in June 2007 in Washington, D.C. (AAPG-SPE IMRC 2007) accountants are able to deal with probabilistic methods; but, the current SEC regulations call for certainty in our uncertain world

**E&P Investors** are buying assets, either a producing property or shares in a company.

When purchasing a property you would like to have your best technical estimate of production over time with associated costs and product prices. In a competitive environment, a successful purchaser will not base their purchase price on 1P reserves or

year end prices and costs. Typically 1P, 2P, 3P, and contingent resources are assessed and different weighting given to each category. The purchaser will use their internal views on future pricing and costs. A common observation is that sellers will not sell at their assessed 1P reserves and successful buyers will pay for 1P, 2P plus a component of the contingent resource and 3P reserves.

When assessing the purchase of shares many investors will rely on the guidance provided by Investment Analysts (IA). The IA will review the current value and future potential of a company and they will then make buy or sell recommendations. IA have proprietary tools which their firms have developed to derive an E&P company's value based on historical trends and their spin on developments the firm they are evaluating are investing in. They do not use 1P reserves as a proxy for company value, nor do they use yearend pricing or other assumptions mandated by the SEC for 1P reserves. IA recognize that mandating reserves based upon year end pricing does not "make it so" for the next 20 plus years despite the SEC being the number one regulator. Savvy IAs are aware that a barrel in country A or company A is not the same as a barrel in country B or company B.

What would investors prefer to see? Ideally, of course, they would prefer full disclosure of 1P, 2P and 3P reserves and the same categories for contingent resources. They would also like to see all of the data which E&P firms consider proprietary so they can make better educated decisions. Due to the competitive nature of the E&P business many of the details which investors would ideally like to see will remain confidential. In summary, 1P reserves are of limited value to Investors.

**E&P Management**, use their staff's reserve estimates for several purposes. We will discuss three keys uses, external reserve estimating, incentive programs and project investment or divestment decisions.

For reserve reporting companies must report the volumes of hydrocarbons that can be specifically booked as reserves following the governing regulatory standards (e.g. SEC). As discussed these values are designed to be conservative in nature. In some jurisdictions the use of probabilistic reserve reporting for 1P and 2P are mandated and 3P disclosure is encouraged. The initial reserve booking for major projects, using current SEC rules, will bear little resemblance to the reserves that a firm will base their project economics on. This is a common misconception by investors, IA, Accountants and senior decision makers. More on this later.

Corporate incentives will often have a reserve component. In exploration business units the reserve targets are often based on contingent resources and or 1P plus 2P reserve categories. As there is no external scrutiny of contingent resources or 2P reserves they can be subject to manipulation. In producing assets the target is often 1P reserves and in more progressive firms 1P+2P. Managers who have authorized billions of dollars in offshore platforms will want to see the expectation case reserves on the books as soon as possible. When they see P90 levels booked there is a strong bias to request book values which are closer to what the firm truly believes will be there. Comments such as, "If that is all the reserves we can book why the heck did we spend \$x Billion on development?" are illustrative of this common misunderstanding.

For project authorization most E&P firms will make their investment decisions on a portfolio basis. This is an acknowledgement that we are dealing with parameters which have tremendous uncertainty. Our staff is expected to make their best technical

judgments of the resources in an unbiased manner. For any given project our best technical estimate should be viewed as the P50 of our distribution, such that 50% of the time the results are higher and 50% of the time the results are lower. Most of our resource probability density functions (pdf) are right-skewed and are commonly represented with a “clipped” lognormal pdf. In these typical pdfs the mean will always exceed the P50 or median value, and the P90 value is a very conservative yet possible outcome. When decisions are made on a portfolio basis, management has an expectation that the portfolio will deliver on average the mean of their portfolio. The larger the firm, the greater the number of projects in the portfolio; therefore the volatility of outcomes relative to the mean expectation case is lower. Since smaller companies have greater portfolio volatility, their managers would be well advised to set their expectations closer to the P50.

In making business decisions all companies recognize that assessment of resources beyond what may be booked as 1P are essential for project decision making, portfolio management plus the setting and achievement of long term targets. While 1P or lower is a plausible outcome 10% of the time, it is not what sound business decisions should be based upon. This realization is often misunderstood.

### **.Internal and External Challenges to Responsible Reporting**

To illustrate some of the issues and challenges related to petroleum reserves classification and estimating (please note the key word **estimating, not calculating**), consider a simple exercise about estimating under uncertainty.

Take a brief look at Figure 1. The objective is not to count the beans in the figure but rather, to make two estimates. Your best technical estimate and an estimate of how many beans you are reasonably certain there are. The number of beans of which you are reasonably certain will be your estimate of the “Proved” number of beans.



Figure 1 – Bean Photograph

When asked for our best technical estimate we are trying to estimate a value where we expect the actual number to be higher 50% of the time and lower 50% of the time. This is the median of the distribution and is referred in the PRMS (Petroleum Resource

Management System, SPE et al, 2007) guidelines as the 1P+2P estimate. When we contemplate a “Proved” number of beans, we are thinking about a specified number (or more) that we are “reasonably certain” will be there. As we will see, the phrase “reasonable certainty” is the operative criterion in determining Proved reserves.

Note that from the simplicity of the wording, the phrase ‘reasonably certain’ is in reality a probability statement, except that no confidence-level (or probability) is specified. Of course that can lead to the situation where it is up to the individual reserves estimator to sense his or her “reasonable certainty”. Students who work as geoscientists or reservoir engineers in our courses indicate that “reasonable certainty” connotes a confidence level of anywhere from 99% to 50%\*. Some actually describe motivation in their company to state that “reasonable certainty” is whatever level it takes to get their project authorized and moving forward towards commercialization. (Qualified reservoir engineers have also noted this broad initial confidence level and see the challenge to standardize that view to a high confidence number, such as 90 %.)

In our education and training courses, we use word and bean exercises which are targeted towards better estimating of subsurface uncertainty. Our two major findings are that professionals cannot directly estimate P90, P50 or P10 levels and that commonly-used words and phrases, without associated probabilities, have a broad range in meaning by individual professional interpreters. This range of confidence levels for “reasonable certainty” was recently corroborated by industry reserve experts attending the June 2007 AAPG-SPE International Multidisciplinary Reserves Conference in Washington, D.C.

All of the participants in the Washington conference were given a survey which is similar to those we routinely run in our courses. The survey and results (generated and compiled by co-authors Gouveia, McLane and Rose) were surprising if not shocking to many of the participants.

<u>Word or Phrase</u>	<u>Confidence %</u>	<u>Rank</u>
Probable	_____	_____
Likely	_____	_____
Certain	_____	_____
Most likely	_____	_____
Possible	_____	_____
Reasonable Certainty	_____	_____
Proved	_____	_____
Expectation Case	_____	_____
Potentially recoverable case	_____	_____
Hoped	_____	_____

Figure 2 – Word Survey Form

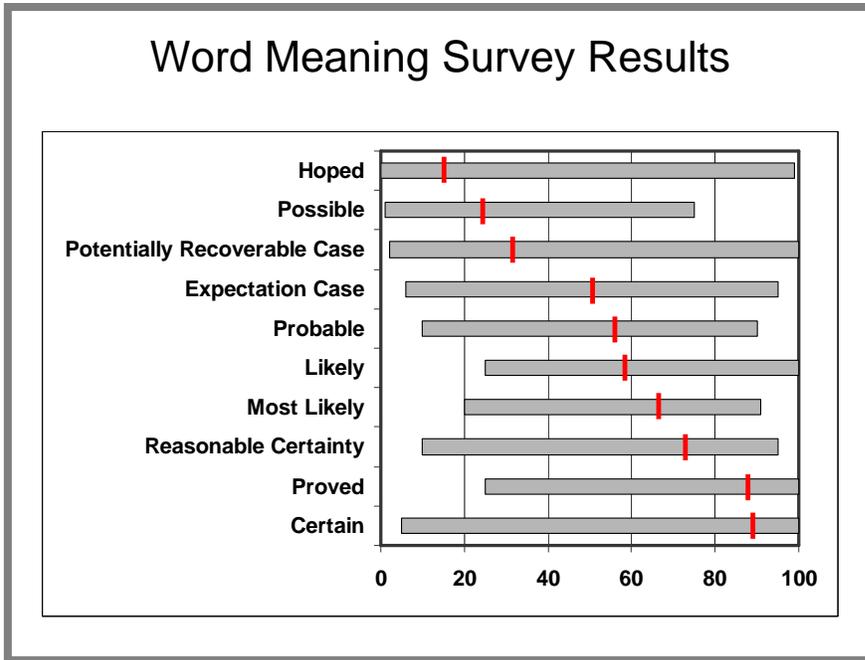
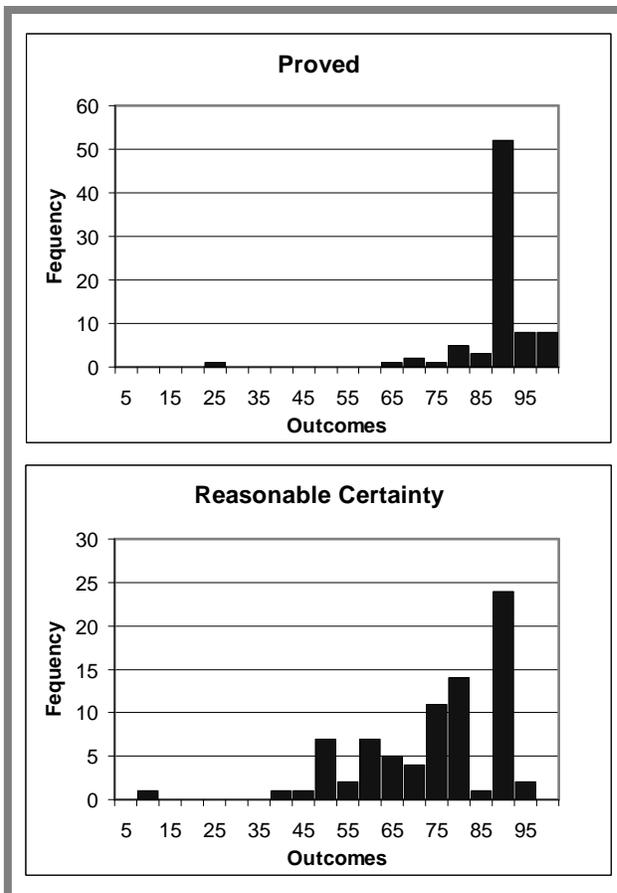


Figure 3 – Word Survey Results

Figure 3 presents the overall results of the survey. Note that when words are used to describe uncertain outcomes, the result is a broad range of interpretations by informed industry professionals. Participants expressed shock and dismay at the results. One well known industry leader stated, “How can this be so? We are talking about the English language”.



To dismiss the notion that the spread must be due to a few individuals who may not have slept well the night before, we presented histograms, Figure 4, of the results for the phrase “reasonable certainty” and the word “proved”.

Figure 4 – Word Survey Histograms

Having conducted this exercise numerous times, we can attest that the results reveal a common pattern. Whether it is a survey of the industry leaders attending the Washington conference or industry professionals that attend our worldwide training courses, the results are eerily similar. Given the established linkage between Proved reserves and the term “reasonable certainty”, the results continue to astound.

What we have attempted to illustrate above is that words, such as reasonable certainty, have and will continue to lead to broad ranges in interpretation. We note that the kurtosis is much higher for “proved” than “reasonable certainty”. The demonstrated interpretive range for “reasonable certainty” will continue to be a driver of reserve booking bias. One of the co-authors of this paper, J. Gouveia recalls his early training as a Reservoir Engineer in 1982. Proved (1P) reserves were to be booked as the Expectation case and the Expectation case was the mean. As the SEC increased its scrutiny in the latter 1980’s, Proved reserves were aligned somewhere between the P50 and lower. With the clarification in the latter 1980’s that the 1P+2P category was more or less the P50, it should have been difficult to argue a 1P in excess of P50. As professional engineers we were to use our expert judgment to determine what level we were reasonable certain of. In mature properties where good linear extrapolations of rate versus time could be made, we were reasonably certain of the P50 case.

The Society of Petroleum Evaluation Engineers (SPEE) has taken exception to the use of the P90 as a proxy for the SEC’s 1P definition based on “reasonable certainty”. In their April 2007 Newsletter, Russ Long of the SPEE (Long, 2007), stated his view that the historical interpretation was that “reasonable certainty” was best represented by the mean of the distribution. While we agree with this as a historic view, we do not support it going forward. It has taken many professionals from the AAPG, the SPE and WPC many years to derive a consensus view of what probability levels should be associated with 1P, 2P and 3P reserves and contingent resources. We believe that the time for debate is over and the time to implement is now. The two remaining issues we see going forward are reserve aggregation and how to teach our professionals to estimate in ranges to derive unbiased P90 and P50 values. We will address both of these issues later in this paper.

Let us return to your P90 estimate of the bean slide. As you ponder your estimate (please do not go back to Figure 1 and count beans; that would hardly be fair in an *estimating* exercise), let’s examine the complications that may arise in extending this exercise to the work place.

First, depending on the culture and reward system at your organization, a larger estimate may be in your personal interest. A larger estimate, made public, may benefit the price of your company shares, the value of your stock option or your annual bonus.

Second, your supervisor, or other members of your management team may actually prefer larger estimates. Once again the reasons can be many (and indeed have been considered as ‘motivation to curb’ in the Sarbanes-Oxley Act, passed by the United States Congress in 2002), but tend to be related to company culture or the current reward system.

Third if the actual outcome turns out to be significantly smaller, rather than larger, your management may be pilloried by the media, disciplined or fired by your firm and (although rare, the media seems to focus on this) fined or even incarcerated by the government

### Addressing the Problem with Confidence

With these serious consequences as possible outcomes, how could your estimate improve? Let's approach the problem by addressing the fuzzy issue of confidence.

As a first pass, we could simply use  $\pm 10\%$ , a general accounting practice that has been used in Joint Operating Agreements designed for AFE (Authority for Expenditure) stewardship. A better way would be to express our uncertainty as a range reflective of the uncertainty. Here, *ranges in numbers of beans* that correspond to different levels of our confidence. For example, we could select a relatively small number, and be pretty sure that there are at least that many beans, *or more* -- 10 beans? 100 beans? 1,000 beans? And we could specify a relatively large number, with low confidence that there could be that many beans, *or more* -- 500? 5,000? 50,000 beans?

### Quantifying Uncertainty

We can do even better by specifying what we mean by "high confidence" and "low confidence". For the point of this example, let's just specify that when we say "high confidence", we saying that we are 90% sure that the true number of beans will be equal to or greater than this estimate 90% of the time. When we are referring to our "low confidence" estimate we think there is just a 10% chance that the true number of beans will be equal to or *greater than* our large estimate. So we can call our low-side estimate P90, and our high-side estimate P10. We can also identify our P50 estimate, which has an equal, 50/50 chance that the actual outcome will be smaller or larger than our P50 estimate. Finally, 80% of all predicted outcomes should fall within the corresponding P90 to P10 range.

We can also take advantage of some simple, yet effective statistical principles that allow us to make much better estimates. For example, when estimating a parameter that arises from the multiplication of independent constituent factors (as opposed to addition), we know (from empirical observations of physical parameters and mathematically from the Central Limit Theorem) that the appropriate distribution of estimates should follow a lognormal mathematical form. In like manner, we also know that independent estimates of beans will plot as clipped lognormal distributions. What is being multiplied? Your eyes and mind work together to estimate height, width, and density of the beans in Figure 1, which you then multiply to get an estimate. So if your P90, P50, and P10 estimates are chosen to fit the appropriate (here, clipped lognormal) form you will actually make better estimates!

We call these distributions of how certain parameters are arrayed in the earth "clipped lognormal distributions". True lognormal distributions asymptotically approach zero at the low end and go to infinity. In nature we know that there are natural limits to these distributions which we refer to as "nature's envelopes". The application of nature's envelopes to a lognormal distribution results in our "clipped lognormal" distribution. Having the appropriate distribution shape communicates additional information to better manage expectations. Examples of nature's envelopes include distributions of in-place resources for a geologic trend, column heights that may increase in a systematic fashion versus depth in a basin, and net sand thickness that typically increases with gross interval thickness representing depositional accommodation space.

This approach quickly evolves into an 'adjust and iterate' procedure that can readily expose (and thus help you greatly reduce) estimation bias. We refer to the process, whereby we validate the end members of a distribution, as "reality checking". It is the "reality checking" process that is a critical component in significantly reducing estimation bias. Simply put all points within the selected distribution must fit within the confines of the "clipped" lognormal distribution. If we are talking about a multiplicative product, for example, reserves, then we extrapolate our P90 and P10 estimates to their reality checked end members. Experience has shown us that for new discoveries, the P1 and P99 are good proxies for nature's envelopes. There are of course exceptions but P1 and P99 have been generally accepted as being right in most instances.

Other end points (nature's envelopes) may be used but they must be supported by actual data. A commonly observed example of this is well reserves in down-spaced unconventional gas plays where the distributions may depart from lognormal behavior shortly after the P10 and/or the P90 of the distribution. We can pragmatically treat these distributions as lognormal distributions with "curvature points". For example if the curvature occurs at the P5 and P95 then we would sample the P5 value 5% of the time and never sample a value greater than the P5. We would treat the low end P95 in a similar fashion. The rest of the distribution is accurately represented by the lognormal distribution.

Are all multiplicative E&P distributions "clipped" lognormal? No, but deviation is the exception rather than the rule. We counsel the use of "clipped" lognormal unless the data can prove otherwise. In practice, distributions of commercialized resources have a commercial truncation applied to accumulations. We manage these deviations from lognormal distributions at the low end via what we refer to as commercial truncations. The initial distribution is a "clipped" lognormal pdf but values below a commercial threshold are truncated. The historical fluctuation and recent rapid escalation in product prices has often obscured this commercial truncation

Returning to the "challenges" theme, when considering any Proved amounts of reserves, we are also confronted by additional requirements associated with responsible fiduciary reporting. The crux of these external regulatory challenges, which have generated considerable confusion and debate, once again returns to the definition of Proved reserves, and in particular the vagueness of the key phrase "reasonable certainty" (as stated in the current SEC definition).

### **The Conundrum of "Reasonable Certainty"**

Webster's defines "conundrum" as: "1. a riddle whose answer is or involves a pun; 2.a. a question or problem having only a conjectural answer, 2.b. an intricate and difficult problem." For our purposes we will paraphrase these definitions as a difficult problem with no clear answer.

According to the SEC website:

(<http://www.sec.gov/about/forms/regs-x.pdf>) Proved reserves are defined as "...the estimated quantities which geological and engineering data demonstrate with reasonable certainty to be recoverable..."

For nearly 70 years (Figure 5), professional engineers and geoscientists have been classifying reserves of crude oil, condensate and natural gas. For a clear historical

description, see Yergin and Hobbs (2005). Estimating these uncertain assets is important for many business purposes -- corporate planning, acquisitions and divestitures, financial markets, and production financing. Further, many governments also got involved officially during the 1960's, arising from their concerns about long-term energy supply and economic growth.

The SEC, which was created in 1934 to protect investors from capital market financial manipulation, entered the fray in 1978 with a system designed largely in response to the needs for secure sources for energy arising from the energy crises of the 1970s. Largely as a result of the United States Congress assigning the reserve classification role to the SEC, the focus of the 1978 regulations, which were largely based on existing Society of Petroleum Engineers (SPE) guidelines, changed from its original purpose to "providing information' both for 'informed decisions by government policymakers' and 'for informed investment decisions relating to the oil and gas producing industry.'" (Yergin and Hobbs, 2005)

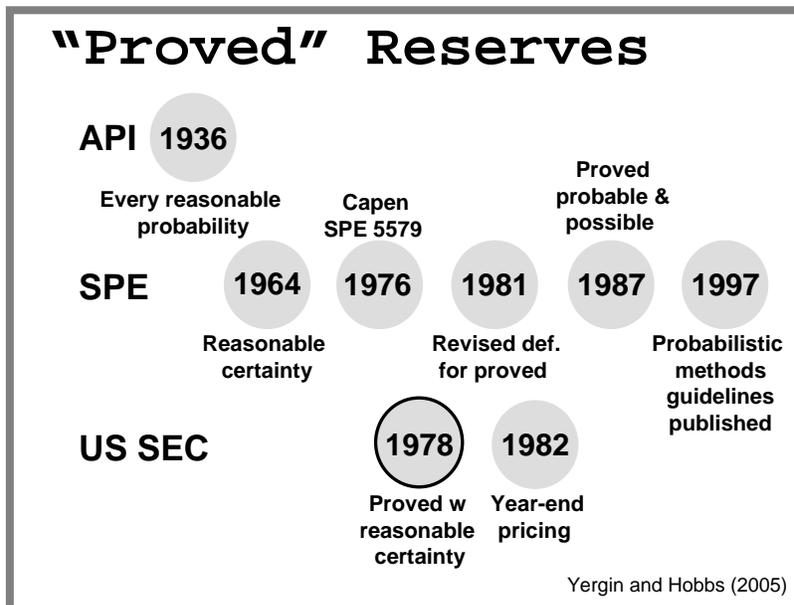


Figure 5 – Proved Reserve History: API to SEC

Until the late 1980's most reserves-estimates were deterministic -- single-number estimates that represented some central tendency of an ill-defined segment of a highly uncertain range of possible outcomes.

Engineers tried to estimate "Proved", "Probable", and "Possible" reserves for a given discovery or producing field. These terms resulted from pragmatic weighting schemes purported to represent successively reduced levels of confidence associated with different possible outcomes. .

In the mid-1980's petroleum exploration began to apply probabilistic estimating methods (Rose, 1992, Capen, 1992, Megill, 1992). Explorers recognized that sustained exploration constituted a "repeated trials game" of many uncertain ventures, which allowed statistical treatment to apply. Accordingly, geoscientists and engineers found that statistics could be the language of geotechnical uncertainty. We became aware of the power of the lognormal distribution, of reality checks, and of project post-audits as tools for calibrating and improving estimating skills. We realized the utility of probabilistic methods in the accelerating field of Portfolio Management. Now, 20 plus years later, probabilistic

estimating is standard exploration practice. The probabilistic “tipping point” was passed in the late 1990’s and is now moving into the production (development) environment. The SPE and World Petroleum Congresses (later Council) (WPC) acknowledged as much in 1997 when they recognized both Deterministic and Probabilistic approaches, and recommended that the “Proved Reserves” category should correspond to 90% confidence (SPE and WPC, 1997).

Even with this acknowledgement, the divide substantially remains (although the gap may be beginning to close) -- exploration is often described in a thoroughly probabilistic realm, whereas production is still mostly described in deterministic values. Old habits (and conventions) die hard, especially when they are reinforced by the SEC. Decision-makers, in a thoroughly uncertain world, can also tend to prefer the illusory comfort of certainty.

### The Conundrum

As we stated previously, note that the SEC definition for Proved reserves is, in fact, a probability statement; even though they specifically refuse to state what probability the term “reasonable certainty” corresponds to (Rose, 2007). Further, as noted by Yergin and Hobbs (2005) the SEC is viewed to have, in practice, moved away from “reasonable certainty” increasingly towards “absolute certainty”. This reflects a profound and distressing lack of public acknowledgement of the fact that hydrocarbon resources and reserves are inherently uncertain. The following provides a vivid illustration of just how uncertain hydrocarbon reserves are.

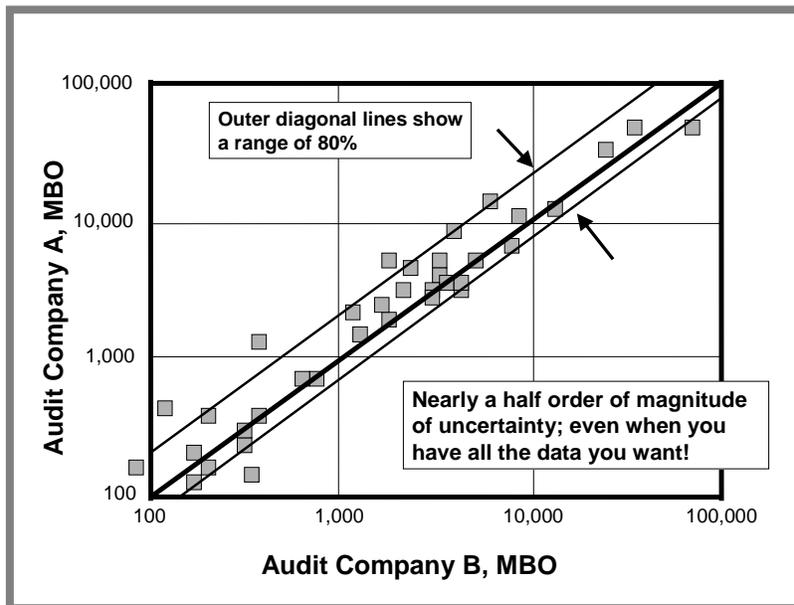


Figure 6 – Log-log plot comparison of reserve estimates made by two reserve audit firms

In this example, a company contracted with two well-known, respected reserve audit firms and asked them to provide reserve estimates for all of their U.S. producing properties. Both audit firms were given the exact same data. The company then compared the reserve estimates provided by the two firms on a simple log-log plot (Figure 6).

While surprising to some, these results are certainly no surprise to those with experience in dealing with subsurface uncertainty. In this example, in which the auditors had an abundance of data, we see that there is nearly one-half of an order of magnitude of

spread, or uncertainty, in the reserve estimates. Here we have a clear illustration of one of the principal drawbacks of deterministic estimates, which by their very nature imply certainty. And yet, for the time being, we are required by the SEC to provide deterministic estimates for booking Proved reserves.

Until recently, our professional associations have not formally objected or strongly countered the SEC's insistence on an unspecified confidence level deterministic definition of Proved reserves.

Beginning in 1997, the SPE, WPC and, later, the American Association of Petroleum Geologists (AAPG) added a probabilistic definition of Proved Reserves as having at least a 90% probability, or P90 that the actual amount produced "will equal or exceed the estimate". They further refined the 1P+2P as having a 50% probability that the actual amount will equal or exceed that estimate. In March of 2007, these associations, along with the Society of Petroleum Evaluation Engineers (SPEE) released the Petroleum Resources Management System (SPE-PRMS) (SPE et al 2007), an expanded set of reserve classification guidelines with greater emphasis on probabilistic definitions of Proved, Probable and Possible reserves. These guidelines are a significant improvement, although many recognize that some significant gaps, or issues, remain – in other words, we as an industry have more work to do. The authors commend the work of the PRMS team and strongly recommend that we as an industry adopt their guidelines. We believe that with stronger support from industry and participation by the SEC, the existing issues with these guidelines can be resolved in short order. It is our observation that without the commitment and active participation by the SEC that the remaining hurdles may never be cleared.

In June 2007, at a joint AAPG-SPE International Multidisciplinary Reserves Conference held in Washington, D.C., SEC representatives, stating a desire for more transparency for investors indicated a willingness to consider an expanded reserves definition that included probabilistic estimates. The lead organization for this will be the International Accounting Standards Board (IASB) through which the U.S. Financial Accounting Standards Board (FASB) will also be working. Though much work needs to be done, improved, updated reserves definitions (including probabilistic) are now on the horizon. Our challenge as estimators remains the same: to responsibly report reserves regardless of the governing (e.g. SEC) rules.

In spite of all of this let us also recognize the wisdom that the SEC rules have historically provided by allowing the flexibility that professional reservoir engineers have felt they needed. In other words, to properly report reserves as Proved, and Proved plus Probable, there needs to be a better recognition in the industry that the definition of 1P and 2P reserves is a function of uncertainty and that uncertainty changes as an asset matures. Without production history many card-carrying Reservoir Engineers will consider reasonable certainty to be the P90 level. After 20 years of production, there is often a tremendous reduction in uncertainty, especially if smooth linear extrapolations can be made. In these cases reasonable certainty will be a value between the P50 and the mean. We also know that for any uncertain distribution, the mean is the best single point deterministic value to represent that distribution, given repeated trials. However, since there is continued encouragement by the SEC to be conservative for the protection of the investor, and to drive reserve scrutiny to lower levels of aggregation, the 1P+2P or P50 is our recommendation for a fair yet conservative approximation of an asset's reserves.

The term “reasonable certainty” has historically given the responsible reservoir engineer the professional freedom to best characterize the uncertainty remaining in an asset. As demonstrated by the word survey presented earlier, this often leads to varying estimates between different estimators for the same entity.

So, on the one hand we have an outdated system that is steadfastly deterministic and yet on the other hand, is flexible enough for experienced estimators to account for confidence levels that vary through the life-cycle of a reservoir. A conundrum? Unfortunately yes. We recommend that adopting the “PRMS” recommendations will address the conundrum directly. “Reasonable certainty” will be defined as the P90 for Proved reserves (recall this is the greater than convention) of a reality checked distribution.

Investor and Accounting standards should be advised that the best, yet conservative assessment of a firm’s reserve should be viewed as the Proved plus Probable or P50 of the distribution. Reserves for accounting purposes would be aggregated probabilistically to the level at which the DD&A is calculated, typically the project level.

Reserves for a corporation should acknowledge full probabilistic aggregation at the corporate level.

As we will discuss next, probabilistic aggregation of a firm’s assets will result in the P50 tending closer to the sum of the mean of the individual assets; the larger the firm the lower the variance between the mean and the P50. While this is a necessary first step towards responsible reporting of reserves, there are additional inconsistencies that still need to be addressed.

The level to which a firm may probabilistically aggregate its reserves for reserve accounting purposes must be agreed to by all impacted parties. For example, we know that determining a company’s Proved reserves by simply adding the Proved reserves of individual independent assets is mathematically incorrect. Simple P90 addition can also dramatically understate the company’s reserves when compared with probabilistic aggregation. We will return to this thought later in this paper.

Equally pressing are the inconsistencies with respect to how reserves may be booked as Proved in one of our industry’s prime growth areas, the deep water trends around the world.

In April 2004, in a letter (SEC, 2004) to companies operating in the Gulf of Mexico, the SEC stated that (with the italics preserved from the original SEC letter) it:

“did not object to your claiming Proved undeveloped reserves in the deepwater Gulf of Mexico prior to a production flow tests since your estimates are fully supported by *all* the results from *all* the procedures included

- Open hole logs – assessment of reservoir characteristics with structure, porosity, hydrocarbon saturation, net pay as a minimum;
- Core samples – characterization of reservoir rock including pay zone permeability;
- Wire line conveyed sampling – sampling for, and measurement of, reservoir permeability, pressure, temperature and fluid properties; and

- Seismic surveys – reservoir structure interpretation in conjunction with well logs.

Please understand that we take this position only with respect to the determination of Proved Undeveloped reserves in the deepwater Gulf of Mexico and no other location.”

However, in recent years industry has pressed the SEC to apply this exception to everywhere else this geologic situation occurs, such as offshore Angola with the same water depth, same amount of logged pay and with nearly identical geological and engineering characteristics. As of November 2007, these situations outside of the Gulf of Mexico would require a production test as one of the requirements that must be met in order to book resources as Proved undeveloped reserves within the same company. Understandably this has created problems and inconsistencies for the industry for which there are currently no remedies.

### **The Advantages of Probabilistic Methods over Determinism**

The fundamental problem with the deterministic approach is that it implies certainty that simply does not exist. It does so by attempting to represent a highly uncertain parameter - or segments of that uncertain range -- with a single, implicitly precise number. It does not attempt to quantify how wide the range of uncertainty is perceived to be around each estimate, except by the use of descriptive terms like “Proved”, “Probable”, and “Possible”. Unless such terms are mathematically defined and widely understood in future guidelines, it can be much more difficult to measure and calibrate our estimating abilities objectively. As a result, the deterministic method can actually (through the introduction of estimation bias) facilitate technical and financial unaccountability to Professionals interested in self-improvement; to Clients and Employers; to Investors; and to the General Public, who have a legitimate interest in soundly-based energy policy for their countries. For further discussion of the advantages of probabilistic methods over determinism see Rose (2007).

As addressed earlier we are addressing three distinct needs here. One of the challenges faced by those trying to develop a “universal” reserve classification system is the fact that there are at least three “customers” with different priorities:

- 1) Investors, wanting an accurate representation of asset value (which Proved reserves do not provide because companies and investors know there is value beyond the Proved category and are willing to pay for it); and
- 2) Regulators such as the SEC needing to develop objective, consistent, yet conservative Proved reserves for their own energy security and policies. In nations where probabilistic reserves have been accepted, Proved plus probable or P50 is viewed as the best single point representation;
- 3) E&P Management teams who need to authorize projects with the best interest of their shareholders in mind. As previously outlined Managers should make decision in the context of their corporate portfolio. For large corporations funding decisions should be made with an acknowledgment of an opportunity’s volatility and recognition that the best single point representation of all possible outcomes from a portfolio basis is the mean.

Considering that there are perhaps different needs, let us contrast Determinism with the Probabilistic Method. When “Proved (1P)” means 90% confidence, we should expect 10% of all such reserves estimates to turn out too low, and 90% to exceed our “Proved” threshold. Proved plus Probable (2P) reserves means 50% confidence, such that half the time the result will be higher and half the time it will be lower. For Proved plus Probable plus Possible (3P) the result will be higher 10% of the time and the result will be lower than the 3P estimate 90% of the time. With this broadened approach, we have an improved basis for calibration and accountability, since those estimators can track where the actual amount falls within (or outside of) their probabilistic forecast. Our experience has been that systemic estimation biases quickly reveal themselves to our clients that embrace performance tracking.

The Probabilistic approach describes an uncertain parameter as a cumulative probability distribution, with estimated confidence of finding that value or more assigned to every value along the distribution, typically from 99% confidence to 1% confidence. Through rigorous performance tracking, the actual results can be regularly compared to see where they fall within the prescribed probabilistic range (see for example, Otis and Schneidermann, 1997); and thus documentation of biased or poor estimating (as well as confirmation of good estimating). The applicability of a disciplined feedback loop actually promotes professional accountability (Citron et al, 2002), as it allows calibration for future efforts and thus encourages learning since any biases can be pinpointed, measured and hopefully reduced.

We do note that the SEC specifically stated in 2001 (SEC, 2001) a clarification that they will accept “probabilistic methods” for reserves, as described in the 1997 SPE/WPC guidelines, with the proviso that SEC-defined limiting criteria (such as “lowest known hydrocarbons”) are adhered to. The SEC also recognizes that the “reasonably certain” qualifier of Proved reserves means that it is possible (though very infrequent) that a field will ultimately produce less than the booked Proved reserves; though clearly the expectation is the field Proved reserves will grow with time. This acknowledgement that Proved reserves were the P90 or less (the impact of the other constraints) was a major departure from the view that many had historically held that “reasonable certainty” could be the “expectation case”. With the new (2001) guidance, a well with many years of well characterized decline behavior would need to be booked at a level which was clearly too pessimistic relative to how it had historically been treated. It is our view that this is one of the key points of dissent which was not and has not been addressed.

The observed behavior that required addressing was major reserve write downs by several large E&P firms. The cause of these major write-downs was in all cases bias. The SEC’s response was to mandate the booking of more conservative values to reduce the impact and frequency of reserve write-downs. In other words they, like many other large organizations, treated the symptom instead of the cause. The root cause was bias and to a lesser extent lack of historical clarity on the definition of reasonable certainty. We shared earlier that we support Russ Long’s view (Long, 2007) that “reasonable certainty” was viewed in the 1980’s as the “expectation case” which was arguably either the mean or the P50 depending on the size of your firm.

So how do we minimize estimation bias? The short answer is training and post appraisals of our estimates. It is essential that training for our professional staff not be solely geoscience and engineering principles as we have found that all subsurface professionals

require training in statistics, basic uncertainty management and the development of their estimation skills.

Without a rigorous post-auditing mechanism in place to determine the amount of bias, deterministic estimating encourages unrealistic thinking about valuable, but highly uncertain mineral assets among executives, board members, bankers, financial analysts, and stockholders. Thus determinism facilitates their misunderstanding of just how much uncertainty resides within the typical E&P portfolio. Consequently, there may actually be extra work driven into the system in the search for “The Answer” (which often does not exist), rather than recognizing and characterizing any irreducible uncertainty and moving forward with looking for new opportunities (Rose, 2007).

While determinism may enable people who want to maintain false confidence to do so, it does no favors to people who really do want to have a good sense of the uncertainties and risks that are inherent in the E&P business.

#### Probabilistic Methods Help Promote Accountability

The Probabilistic mind-set acknowledges uncertainty up-front, so we devote only enough time, effort and money to get the range of possible outcomes reality-checked. We then stop, archive the forecast, and use the created extra time and money to find and develop new opportunities. At first, this may appear to be less efficient, but over time it will become far more effective than deterministic estimating, because we derive a much greater appreciation of what constitutes the drivers of the uncertainty. This puts us in a position where we can then proactively mitigate both uncertainty and risk. While mitigation takes time and effort, the result is a much higher confidence in meeting our estimates through proactively attacking key concerns.

The outputs from probabilistic resource estimating enhance modern Portfolio Management programs by presenting a clear view of the full range of portfolio volatility, and not simply the upside and the downside. The probabilistic method is universally applicable along the value chain in our business. It works just as well for production forecasting, cost estimating (e.g. drilling), well remediation, water-flood projects, and acquisitions & divestitures.

Adherents of determinism often ask, “Why can’t we apply performance tracking to deterministic estimating?” The answer is you can. While we can audit deterministic estimates, the question remains, “How can we calibrate them?” Ultimately, the best that one can do is to assess whether deterministic estimates are high or low, but there is no real way to calibrate future estimates, other than to say go lower or alternatively higher next time. The recipient of this form of feedback will, of course, be prone to ask, “How much higher or lower?” Predictive accuracy, which is measured statistically, mandates probabilistic estimates. We can never know with confidence the accuracy of a single-value deterministic estimate.

#### Test Application to our “Beans Exercise

Would the techniques suggested above actually improve the estimates of the beans shown in Figure 1? Our studies have shown that people perform far better when estimating probabilistically.

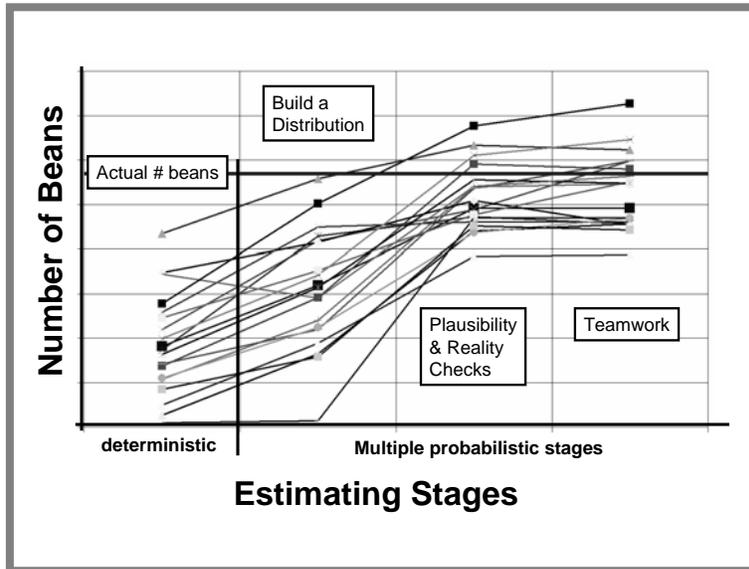


Figure 7 – Plot showing improvement of class bean estimates

The curves in Figure 7 represent the average of estimates from class sizes of 20 to 40 people. Each data point represents the average of class estimates at various stages of the exercise. Values at the far left of each curve represent estimates made as a single deterministic “best guess” or P50 value. The points to the right represent the improvement resulting from first building a probabilistic estimate using a “clipped lognormal distribution”, next they apply reality checks based on additional analog data that they are provided with. The final stage represents the opportunity the estimators have to make a final revision based on comparing estimates from team-mates, which is our proxy for group wisdom.

## A Bridge to the Future

### What do we have now for responsible reporting of petroleum reserves?

As pointed out by Ross (2005) there have been great strides in resource classification systems that work at a corporate or country level. Relative to 1978 (the year the term “reasonable certainty” was codified by the SEC), we clearly have vastly improved technology; improved work processes and growing awareness of the appropriate ethical behaviors in characterization and communication of opportunities. We still have some fundamental inconsistencies in the 1978 system, represented by outdated and parochial definitions. Lastly, relative to 1978, we also note a dramatic globalization of our industry that mandates a broadened international consensus on guidelines.

The Petroleum Resources Management System (SPE et al, 2007) has presented us with reserve definitions that have been embraced by many of the global E&P professional organizations. This ground breaking work, while not complete, should be accepted and built upon.

Regulators, such as the Alberta Securities Commission ([www.albertasecurities.com](http://www.albertasecurities.com)), have embraced probabilistic reserve reporting, along with the commensurate full disclosure of assumptions. To their credit the Alberta Securities Commission (ASC) elected to utilize the reserve standards that industry professionals (SPEE) generated and presented in the Canadian Oil and Gas Evaluation Handbook (COGEH), which is now available in its

second edition. The great strides made by the ASC in implementing a probabilistic based reserves system and the excellent work contained in COGEH should serve as a reference for the SEC in their upcoming overview of their reserve reporting system. While globally we are seeing a congruence of methods, the most notable and significant exception is the SEC.

#### What do we still need for responsible reporting?

The Petroleum Resources Management System (PRMS) has gone a long way towards developing an internationally accepted and up-to-date set of reserve and resource classification guidelines and definitions. Unfortunately not all member organizations of the PRMS guidelines have accepted the P90, P50 and P10 guidance for 1P, 1P+2P and 1P+2P+3P reserves respectively. This is a mandatory first step otherwise we will never achieve global consistency. Providing that link will not only improve communication among all stakeholders, but will also permit some level of calibration for deterministic estimates.

Even though the mathematical techniques are now readily available, there is still a lack of consensus among professionals about probabilistic aggregation beyond the Project, level. There are a number of reasons for this including a lack of understanding or misunderstanding of portfolio aggregation and a philosophical disagreement with respect to the objectives of aggregating as specifically applied to 1P and 2P reserves. It is this issue that we will now address.

#### The Impact of Aggregation Beyond the Single Entity Level

Let's focus on the challenge to responsible reserve reporting: specifically the challenge that relates to the problem of probabilistic aggregation of Proved reserves from single entity reserve reports.

For reserve reporting PRMS explicitly recommends probabilistic portfolio aggregation, taking into account dependencies within and between reservoirs, of Proved reserves up to the project level only. The term "project" is not clearly defined; it can be viewed as an asset or the field. We would recommend that project aggregation be further clarified as the point where the accountants would determine the DD&A for the project. As we will outline later, accepting full probabilistic aggregation will eliminate the confusion over where to define a project's boundaries. PRMS recommends that the now aggregated Proved reserves at the Project level be arithmetically added to determine the aggregated Proved reserves for the company. PRMS acknowledges that this will produce a company-level Proved reserve that may be considerably more conservative than would be derived from probabilistic portfolio aggregation of the project reserves. For a complete discussion see the 2007 PRMS guidelines which can be downloaded at no cost from the SPE's website, [www.spe.org](http://www.spe.org).

For edification in the following discussion, we view the term dependency as whether or not two estimated variables have a relationship with one another. We say there is a dependency if the sampled result of one variable impacts the sampling of the second variable and vice versa. To keep the math simple we will only address first order linear relationships. We quantify how strong the dependency between variables is by use of the correlation coefficient. Relationships between variables can have a positive or negative correlation. Interestingly most subsurface dependencies have positive correlations.

Positive correlations have the counter-intuitive impact of broadening the full range of resulting outcome distribution (resulting in an increased P10/P90 ratio). In other words, the more we know about the relationship between our variables the greater the uncertainty of the combined distributions. This (the notion that the more we know the greater the uncertainty) is counter-intuitive and as such often confused.

Note that while PRMS recommends full probabilistic aggregation to the project level it does not support probabilistic aggregation to the corporate level of the different projects. The flawed argument we have heard is that there are dependencies between projects which if not handled right will result in over estimation of corporate reserves. There are two fatal flaws in this statement. The first is the assumption that dependencies are only important at the highest levels of aggregation. The second is that dependencies between our assumption variables at the well, pool and project levels have in fact been handled correctly by our staff. If our staff understands how to deal with the impact of correlation between variables at the project level and lower, then why would they not understand their impact when we aggregate to the next level of our portfolio? The solution here is to increase our understanding of basic statistical principals rather than making the aggregation invalid at one level to protect us from bias. If elimination rather than education is the solution, then probabilistic aggregation must be eliminated at all levels of reserve aggregation.

In practice we see little subsurface dependency between projects and strong subsurface dependencies within projects. An example of a common subsurface dependency is area and net pay. In many traps it is not possible to have a large productive area without large net pay. Likewise it is not uncommon to observe small net pays associated only with smaller productive areas. When incorporated into volumetric models, this type of strong area to net pay correlation can significantly increase, often doubling, the mean value of the calculated volumetric reserves distribution. The strong correlation between productive rate and reserves in Unconventional gas plays has a similar impact on the economics of those opportunities.

So what are the dependencies that we are concerned with that would distort our aggregation of reserves at the corporate level? Stated another way what do our subsurface estimates of reserves in a mature water flood in West Texas have to do with our Firm's reserve estimates in Indonesia? The answer from a correlation perspective is very little. At the project to corporate aggregation level the P10/P90 ratios are low enough that weak correlations, if they existed, would have negligible impact.

Are there external variables which impact all projects? Yes, oil price is an excellent example of a global variable. Oil price projections impact all projects so yes we can say that reserves are dependent on oil prices. But oil prices are not dependent on reserves and therefore we should not include a correlation between oil price and reserves in our simulation model. Oil price is an example of a global dependent variable as it impacts all cases but it is not a parameter that should be modeled with a correlation coefficient relative to reserves. Global variables impact all projects but there is no relationship between projects that must be accounted for when assessing the impact of oil prices. To clarify why we do not use a correlation coefficient for oil price, we can work through the following logic. We know that increased oil price will increase reserves as the economic limits are lower. When we consider the reserves we need to ask if it is possible to sample the low end of the reserves distribution given high oil prices. Have we seen reserve write-downs in fields in an escalating price environment? Of course we have. Subsurface

uncertainties such as the production response to enhanced oil recovery (EOR) processes are not correlated to oil prices, but high oil prices do encourage EOR projects.

When we are aggregating projects, we do not mathematically distort the reserve values as a result of their probabilistic aggregation from the Project to the corporate level. In setting up the probabilistic aggregation model for a corporation, variables, such as oil prices, and cost inflation must be sampled outside the reserve aggregation loop. For clarity, we would first sample from the oil price and cost inflation factor distributions and then perform the Monte Carlo probabilistic aggregation of the project reserves in the portfolio. Corrections for local pricing conditions would of course be applied to the sampled oil price. We note that a Monte Carlo analysis will allow us to build in a correlation between cost inflation and oil price. It is the use of these documented correlations that brings reality into our Monte Carlo analyses. The power of Monte Carlo simulation is not simply the ability to build ranges of inputs for oil price and then ranges for cost inflation. The true strength of Monte Carlo analyses lies in understanding the ranges for our input variables and how variables are correlated.

The solution is education for both regulators and reserve estimators alike, rather than arbitrarily setting limits on aggregation to protect us from mathematically correct; but, often counterintuitive aggregations.

What difference does this make? Let's look at the following example.

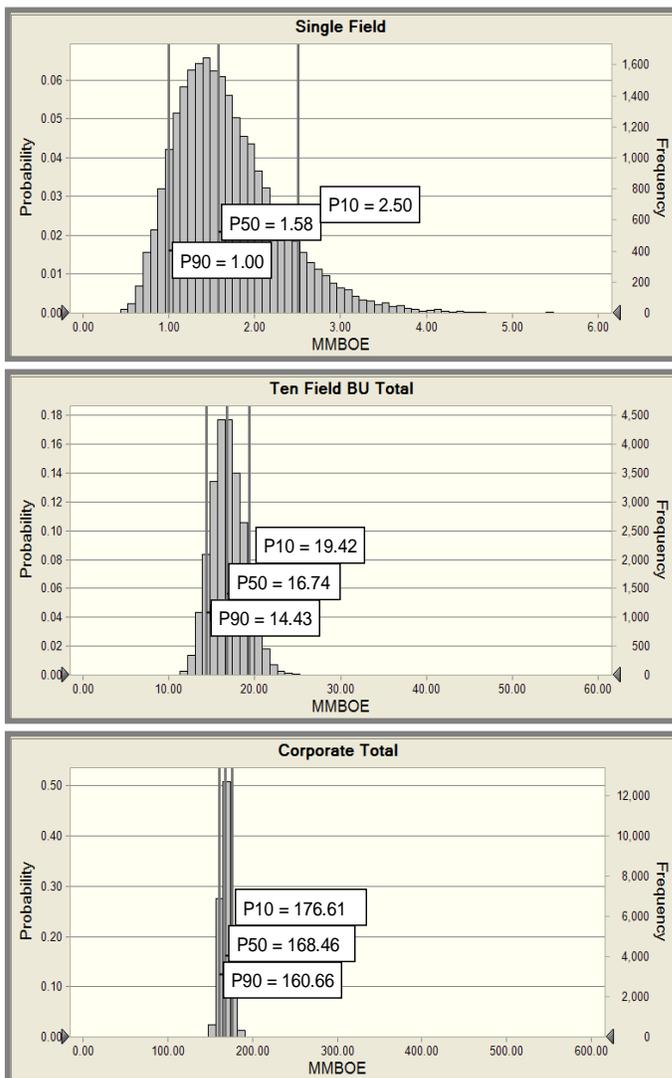


Figure 8 – Reserve Frequency Plots (PRMS Guidelines)

The top plot displays our “clipped” lognormal distribution of the estimated reserves for a single field. Based on PRMS guidelines the following reserves levels would be recommended: 1P of 1 MMBOE, 1P+2P of 1.58 MMBOE and 1P+2P+3P of 2.50 MMBOE.

The middle plot displays the results of probabilistic aggregation of 10 identical single fields to a Business Unit (BU) level. If managed as a project the following reserves levels would be recommended based upon the PRMS guidelines: 1P of 14.43 MMBOE, 1P+2P of 16.74 MMBOE and a 1P+2P+3P of 19.42 MMBOE.

The bottom plot displays the results of probabilistic aggregation of 10 identical BU's to the corporate level. If probabilistic

aggregation at the corporate level were permitted the following reserves levels would be recommended: 1P of 160.66 MMBOE, 1P+2P of 168.46 MMBOE and a 1P+2P+3P of 176.61 MMBOE.

Note that the X axis scale for each plot in Figure 8 has changed. It is 10 times broader at the BU-level and 100 times broader at the corporate-level relative to the single field case. The distribution shapes change with aggregation from “clipped” lognormal for the individual field towards a normal distribution with aggregation of independent events, as predicted by the Central Limits Theorem. Note that the P50 and mean of the corporate case are very close. This is a clear indication of distribution which is fitting a “clipped” normal distribution.

A common misunderstanding is the belief that we can simply add the ten P90 values from each individual field to report 10 MMBOE as the Proved reserves for this Business Unit. The mathematically correct probabilistic amalgamation shows the P90 or 1P Proved reserves of the combined 10 fields to be 14.43 MMBOE. The conservative value of 10 MMBOE, obtained by the arithmetic addition of the individual field P90’s is actually associated with a cumulative probability of 99% on the probabilistic aggregation of the 10 fields within the single BU.

Next we will assume that the company has ten Business Units, each with 10 identical fields, so that the total company portfolio is comprised of 100 fields.

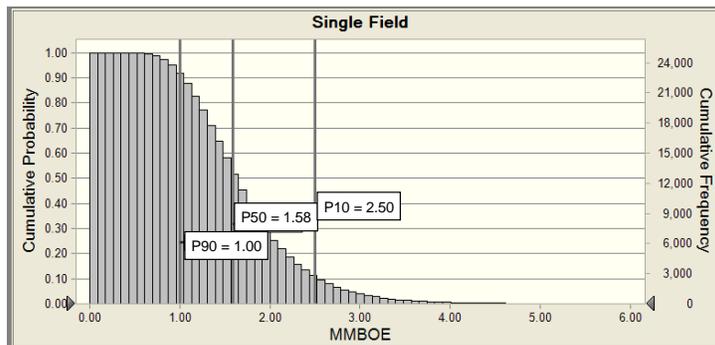


Figure 9a – Reverse Cumulative Plots for a single field

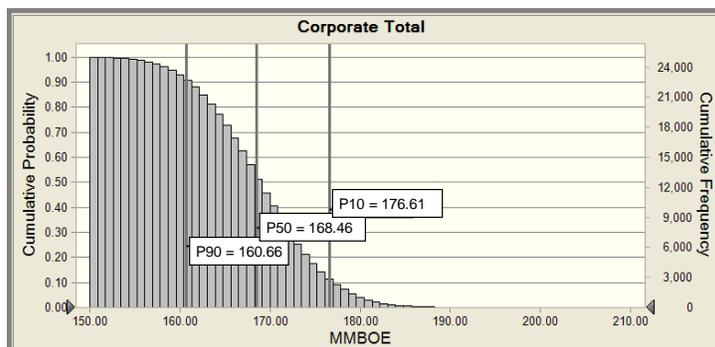


Figure 9b – Reverse Cumulative Plot for 100 fields

From Figure 9 we see that arithmetically adding the 100 fields P90’s would result in a reported Proved reserve of 100 MMBOE, rather than the probabilistic amalgamation P90 or Proved reserve value of 160.66 MMBOE. Note that 100 MMBOE falls at a cumulative

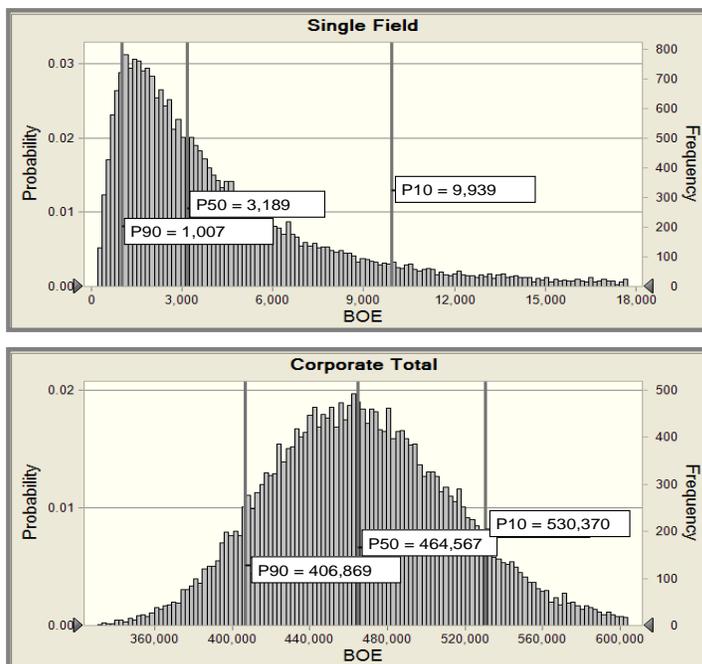
probability greater than 99.9% on the probabilistic aggregation of the 100 fields. Similarly, the P90 of the probabilistic 100 field amalgamation of 160.66 MMBOE is actually greater than the arithmetic addition of the 100 individual fields P50 values (158 MMBOE). We note that the larger a firm is the lower the percentage volatility in their proved reserves.

This is a point that all savvy investors are aware of and one of the reasons that firms such as ExxonMobil are referred to as “Blue Chip”. As there are no subsurface correlations between the projects the mean of the reserve summation is equal to the sum of the individual means. From Figure 8, the single field mean is 1.686 MMBOE and the 100 field mean is 168.55 MMBOE. As we noted earlier, the historical context of “reasonable certainty” as the expectation case is interestingly similar when viewed in the context of the corporation. Note that the P50 of the 100 Field Corporate look is 168.46 MMBOE which is within 0.05% of the mean reserves of 168.55 MMBOE.

Conundrum solved? Probabilistic reserve aggregation may serve as the way forward for organizations to find a common ground in creating universal reporting standards. As this discussion highlights, the debate between organizations has been occurring without the context of the well level, project level, BU level or corporate level. Aggregation of P90 derived Proved reserves is in alignment with the historical need to aggregate mean reserves to derive an “expectation case”, of the mean for the corporation.

Before leaving the topic of aggregation, we need to discuss another apparent conundrum. In this case it is a problem that can actually be solved by understanding the principles of portfolio aggregation.

Let us compare two firms: a small one with a 50% interest in two wells (net wells = 1) and a larger one with interests in 101 wells (net wells = 100). All wells for both companies are in the same reservoir and in fact the larger firm owns and operates the other 50% interest in the smaller firm’s wells. There is great uncertainty in future well performance as they are producing oil from a reservoir with vertical fractures and a strong underlying aquifer. The vertical fractures cannot be imaged seismically and even those viewed on well logs are of uncertain continuity to the underlying aquifer. What we do know, with ‘reasonable certainty’, is that each year 10% of the wells on average will water out and due to the nature of the active water drive will never be returned to sustained oil production with reasonable certainty.



The resulting “single field” and “corporate” reserve frequency plots are shown in Figure 10.

Figure 10 – Single Field and Corporate Reserve Frequency Plots

The small firm accepts the reserve report generated by the operating larger firm which recommended a P90 of 1,007 BOE, a P50 of 3,189 BOE and a P10 of 9,939 BOE on a per well basis. For simplicity let us assume that we have the nirvana of oil fields where every well is identical. Accordingly, the small firm books 1,000 BOE as its Proved reserve level. In reading the annual report of the Operator they note that the Operator has booked Proved reserves of 406,869 BOE. Some quick math by the small firm's owner reveals they have booked as Proved an equivalent of 4,068.7 BOE per well. Should they "blow the non-compliance whistle" or is this simply an apparent conundrum?

This is of course an apparent conundrum which results from a common misunderstanding of probabilistic aggregation. Because the larger operator has 100 net wells we know that they will lose 10 wells per year on average. We also know that 90% will on average keep producing each year. All savvy investors will be aware that investment in the larger operator is a safer investment. The small operator goes on the offensive and states that their well could be the last one in the field to be producing and could recover well in excess of the booked proved reserves. Is this a true statement? Of course it is; but, the probability that they will have the last well standing is about 2%. Is there upside in investing in his company? Yes. Is there downside? Yes. Why the apparent conundrum with respect to Proved reserves when their per-well mean reserve is the same? It is simply a numbers game. With 100 net wells the larger firm can deliver with "reasonable certainty" a much higher reserve level. They are not exposed to total failure for many years. The smaller firm is exposed to total failure each year and hence their delivery of "reasonable certainty" is significantly lower. Apparent conundrum solved.

### The Current State

Clearly there is much that needs to be done within the industry and regulatory agencies to deal with these inconsistencies. For now, responsible reserve reporting means: (a) estimating probabilistically to account for, and represent the uncertainty; (b) estimating without bias; and (c) aggregating Proved reserves to the appropriate entity level in accordance with the prevailing laws and rules – for the U.S., that means the rules set by the SEC / FASB. This may bring you back to square one.

But it also means that we as an industry and as professionals should continue to constructively challenge the SEC's rules and encourage the SEC to adopt reserve classification rules that are up to date and technically sound.

What can we control as professionals? We can control the amount of bias in our estimates by recognizing and systematically dealing with the uncertainty in our estimates. This brings us to our last section.

### Responsible reporting mandates archival and usage of numbers beyond the Proved level

Simply put, unbiased portfolio management and budgeting simply cannot occur without making and preserving estimates of the remaining resource base beyond the Proved level.

Explorers routinely generate these values since they need to be able to show the growth potential available to their company. Companies commonly use the terms 1P, 2P and 3P to express their reserve base. In a deterministic system each of these are single discrete values that have all of the inherent problems associated with deterministic estimates –

namely, susceptibility to optimistic bias and lack of quantifiable confidence levels. In a probabilistic system these terms are explicitly defined as 90% confidence for 1P, 50% confidence for 1P+2P and 10% confidence for 1P+2P+3P. It is these values beyond 1P (i.e. 2P and 3P) that are essential in helping companies evaluate and plan future budgets, production forecasts and portfolio models.

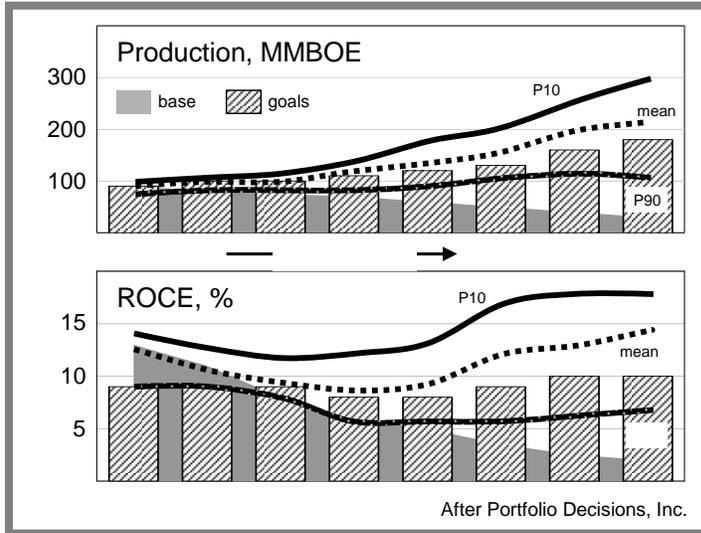


Figure 11 – Model Portfolio Plots

As seen in Figure 11, the model shows the high side (P10), mean and low side (P90) values through future years of key metrics (production and return on capital employed) relative to goals set (and represented by the vertical bars). The filled area in each graph shows the impact of not including any additional potential provided by such techniques (in other words, a base decline).

Clearly, the resources out beyond the Proved level are critical to achieving goals and therefore should be archived and used in portfolio management efforts to deliver on promises. A probabilistic estimating system is the only way to effectively quantify the uncertainty in the portfolio.

## Conclusion

Responsible reporting of petroleum reserves requires an understanding of the amount of uncertainty remaining at each stage of an asset life cycle; from exploration prospect to appraisal to field delineation to development and depletion. Therefore at each stage the reporting is largely an estimate. Effective estimating should be treated as a process that describes uncertainty probabilistically with: a range of outcomes portrayed in the appropriate distribution type, applying plausibility and reality checks to detect and filter out unrealistic values, and the discipline of regularly comparing the estimated uncertainty range to the actual results as they become available. We have found this process enhances accountability and improved estimating accuracy in organizations much more effectively than estimating with single-valued, deterministic numbers.

Effective estimating often faces internal challenges due to company cultures and reward systems that may motivate or induce optimistic bias. External pressures associated with the major regulatory agencies impose the vague, undefined term “reasonable certainty”

(among other specifications) to qualify a portion of any resource base as a Proved reserve. The term “reasonable uncertainty” is actually a probability statement, but to date the SEC and other regulating agencies have failed to define this phrase, nor provide a specification of the confidence level that should be associated with it, to promote more consistency and calibration for responsible reporting. Accordingly, we support the PRMS guideline that there should be a 90% confidence associated with Proved reserves. As entities are aggregated, responsible reporting dictates that the confidence level be applied to the aggregation, which is not the same as the addition of the 90% confidence level values for the individual entities. Commensurate with our industry’s movement to probabilistic reserves will be mandated full disclosure of 2P and probably 3P reserves and contingent resources so that Investors can make educated investment decisions. There are many perceived conundrums in moving from deterministic to our advocated position of full probabilistic aggregation of reserves. While acknowledging the challenges, we believe that the key issues (not unlike many of our global problems) can be solved by education of the users of reserve estimates in the modern world of probabilistic reserves.

### References Cited

Alexander, J. A. and J.R. Lohr, 1998, Risk Analysis – Lessons Learned: SPE 49030, Society of Petroleum Engineers Annual Meeting, New Orleans.

Capen, E. C., 1992, Dealing with Exploration Uncertainties, in Steinmetz, R., ed., The Business of Petroleum Exploration: “AAPG Treatise of Petroleum Geology – Handbook of Petroleum Geology”, Chapter 5, p. 29-61.

Capen, E. C. 1996, A Consistent Probabilistic Approach, SPE Reservoir Engineering, February 1996, 11(1).

Citron, G.P., D.M. Cook, and P.R. Rose, 2002, Performance Tracking as a Portfolio Management Tool, AAPG 2002 Annual Meeting, March 10-13, 2002, eposter, p. A32.

Gouveia, J. , P.R. Neculae, and P.R. Rose, 2007, Why it is time for Probabilistic Reserves, (slides only), SPE 150 Years of Romanian Oil Conference, Bucharest October 15, 2007.

Long, Russ, 2007, Probabilistic P90 and Reasonable Certainty Alternate Definitions of Proved or the Same? Society of Petroleum Evaluation Engineers April 2007 Newsletter, p. 8 – 9.

Megill, R.E., 1992, Exploration Economics, in Steinmetz, R., ed., The Business of Petroleum Exploration: “AAPG Treatise of Petroleum Geology – Handbook of Petroleum Geology, Chapter 10, p. 107-115.

Otis, R.M., and N. Schneidermann, 1997, A Process for Evaluating Exploration Prospects, AAPG Bulletin, Vol. 81, No. 7, p. 1087-1109.

Rose, P.R., 1992, Chance of Success and Its Use in Petroleum Exploration, in Steinmetz, R., ed., The Business of Petroleum Exploration: “AAPG Treatise of Petroleum Geology – Handbook of Petroleum Geology”, Chapter 7, p. 71-86.

Rose, P.R., 2007, Measuring what we think we have found: Advantages of probabilistic over deterministic methods for estimating oil and gas reserves and resources in exploration and production, AAPG Bulletin, Vol. 91, No. 1, p. 21 – 29.

Ross, J.G., 2001, SPE/WPC/AAPG Resource Definitions as a Basis for Portfolio Management, SPE 68573, SPE Hydrocarbon Economics and Evaluation Symposium, 2-3 April, Dallas, Texas.

Ross, J.G., 2005, A Look Ahead – Some Unresolved Issues, presented at the SPE Seminar on Estimating and Reporting Reserves, London.

Society of Petroleum Engineers and World Petroleum Congresses, 1997, Petroleum Resources Classification and Definitions, 10 pp, available from [www.spe.org](http://www.spe.org).

Society of Petroleum Engineers, World Petroleum Congresses and American Association of Petroleum Geologists, 2001, Guidelines for the Evaluation of Petroleum Reserves and Resources, 139 pp, available from [www.spe.org](http://www.spe.org).

Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers, 2007, Petroleum Resources Management System, 49 pp, available from [www.spe.org](http://www.spe.org).

Society of Petroleum Evaluation Engineers (Calgary Chapter), 2007, Canadian Oil & Gas Evaluation Handbook, 2<sup>nd</sup> Ed.

United States Securities and Exchange Commission, 2001, Division of Corporate Finance: Frequently Requested Accounting and Financial Reporting Interpretations and Guidance, March 31, 2001, Washington, D.C.

United States Securities and Exchange Commission, 2004, Letter to Companies with Oil and Gas Operations in the Gulf of Mexico, April 15, 2004, Washington, D.C.  
(<http://www.sec.gov/divisions/corpfin/guidance/oilgasltr04152004.htm>)

Yergin, D., and D. Hobbs, 2005, In Search of Reasonable Certainty: Oil and Gas Reserves Disclosure, Cambridge Energy Research Associates, 121 pp.

### **Acknowledgements**

We are indebted to numerous colleagues who have mentored and shared their insights and ideas with us in the course of our professional careers. We appreciate the helpful and thoughtful comments of Creties Jenkins and his fellow AAPG reviewer, as well as those of Stuart Filler.

### **List of Figure Captions**

Figure 1 – Bean Photograph

Figure 2 – Word Survey Form

Figure 3 – Word Survey Results

Figure 4 – Proved and Reasonable Certainty Histograms

Figure 5 – Proved Reserve History: API to SEC

Figure 6 – Log-log plot comparison of reserve estimates made by two reserve audit firms

Figure 7 – Plot showing improvement of class bean estimates

Figure 8 – Reserve Frequency Plots (PRMS Guidelines)

Figure 9a – Reverse Cumulative Plot for a single field

Figure 9b – Reverse Cumulative Plot for 100 fields

Figure 10 – Single Field and Corporate Reserve Frequency Plots

Figure 11 – Model Portfolio Plots