Reserves Estimation: The Challenge for the Industry

Ferruh Demirmen, SPE, Petroleum Consultant

Introduction

Reserves estimation is one of the most essential tasks in the petroleum industry. It is the process by which the economically recoverable hydrocarbons in a field, area, or region are evaluated quantitatively. Downward revisions of U.S. Security and Exchange Commission (SEC)-booked reserves by some oil companies in 2004 brought the topic under public scrutiny. Confidence in reserves disclosures became a public issue, and there were calls from investors and lending institutions for more-reliable reserves estimates. Oil companies have responded by revisiting reserves-estimation procedures, and SPE, American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), and Society of Petroleum Evaluation Engineers (SPEE) have launched a joint project to train reserves evaluators. A major goal in this initiative is preparation of training modules that represent industry's "recommended practices."

Long before the issue caught the public's attention, however, reserves estimation was a challenge for the industry. The challenge stems from many factors, tangible and intangible, that enter the estimation process, and judgment is an integral part of the process. Uncertainty, along with risk, is an endemic problem that must be addressed. Consequently, the industry's record of properly predicting reserves has been mixed. Despite appeals from some quarters, there currently is no standardized reserves-estimation procedure.

The purpose of this paper is to discuss various issues related to reserves, review reserves-estimation procedures, and make suggestions for improvements. Emphasis will be placed on reserves evaluation at the preproduction stage in which estimation errors generally have the highest economic effect. The discussed procedures pertain to conventional oil and gas reserves. Specific rules relating to booking reserves for regulatory purposes are outside the scope of this paper.

Reserves Definition and Classification

Fig. 1 shows how reserves are part of the petroleum resource base. Under the SPE/WPC definitions, "Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward" (*Petroleum Reserves Definitions* 1997). Commerciality implies commitment or expected commitment to develop reserves within a reasonable time frame. Depending on the degree of uncertainty, three main classes of reserves are recognized: proved, probable, and possible, the last-named two collectively called unproved. Proved reserves are those quantities that have reasonable certainty of being recovered, indicating a high degree of confidence. Proved reserves may be developed or undeveloped. Probable reserves are more likely than not to be recoverable, while possible reserves are less likely to be recoverable than probable reserves. Geological and engineering data form the basis of determination. Proved reserves assume recoverability under current economic conditions, operating methods, and government regulations. For unproved reserves, recoverability may be tied to future economic conditions and technology.

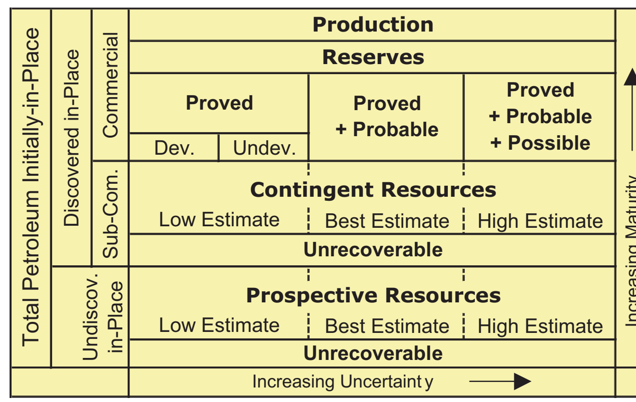

Fig. 1—Petroleum resource classification, based on Fig. 1 of Petroleum Resources Definitions (2000).

In the absence of fluid-contact data, the lowest known occurrence of hydrocarbons generally controls the proved limit. Reserves exclude past production.

Potentially recoverable quantities that do not satisfy the definition of reserves are contingent (discovered but subcommercial) and prospective (undiscovered) resources. Subcommerciality includes technology limitations (*Petroleum Reserves Definitions* 1997; *Petroleum Resources Definitions* 2000).

Ferruh Demirmen, *SPE, is an independent petroleum consultant dealing, in part, with reserves estimation. He has 40 years of upstream experience, mostly in production. Demirmen retired from Shell Intl. Petroleum Mij. as a corporate consultant in production geology responsible for Europe/North Sea, southeast Asia, and South America. He holds a BS degree from the U. of Kansas and MS and PhD degrees from Stanford U., all in geology.*

This is paper SPE 103434. **Distinguished Author Series** articles are general, descriptive representations that summarize the state of the art in an area of technology by describing recent developments for readers who are not specialists in the topics discussed. Written by individuals recognized as experts in the area, these articles provide key references to more definitive work and present specific details only to illustrate the technology. **Purpose:** to inform the general readership of recent advances in various areas of petroleum engineering.

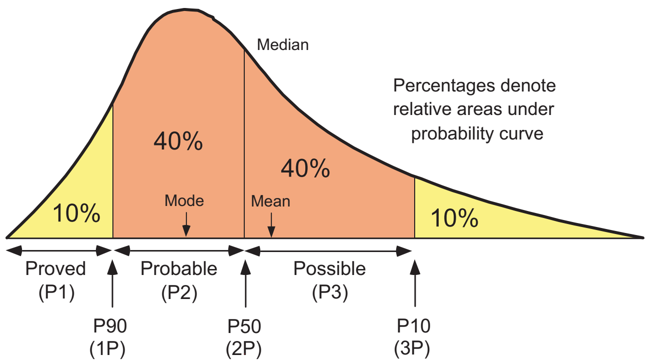

Fig. 2—Probabilistic reserves definition.

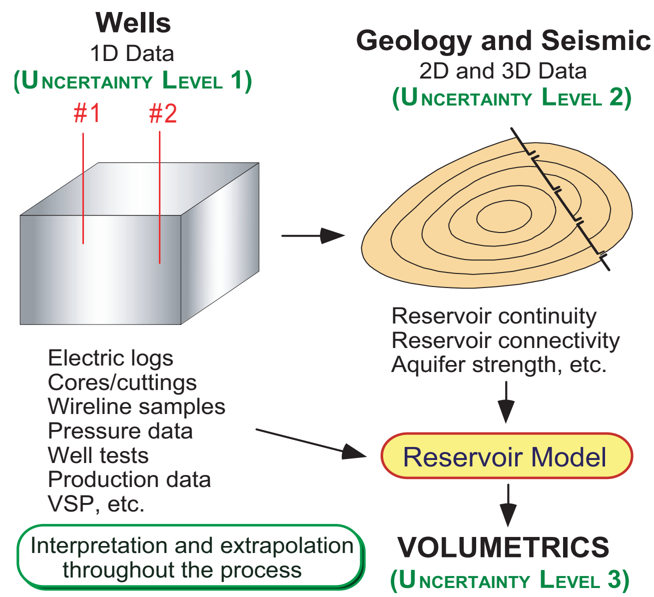

Fig. 3—Sources of technical uncertainty.

Because of ambiguity associated with uncertainty levels in traditional definitions of reserves, probabilistic definitions that quantify uncertainty have gained wide acceptance in the industry. Under SPE/WPC guidelines, for proved reserves, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate **(Fig. 2).** For probable reserves, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves. Likewise, for possible reserves, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves. Fig. 2 shows some common notation (e.g., 1P and 2P).

Reserves categories are subject to change in response to data maturity and other contingencies. While there are exceptions, the usual trend is for possible and probable reserves to move to the proved category and contingent resources to move to reserves category.

In September 2006, SPE issued a draft proposal *Petroleum Reserves and Resources Classification, Definitions and Guidelines* for review in 2007 sponsored by SPE, AAPG, WPC, and SPEE and invited the industry to comment.

Sources of Technical Uncertainty

Reserves estimation is heavily affected by technical uncertainty **(Fig. 3).** The first level of uncertainty is associated with one-dimensional data (e.g., well logs, cores, well tests). These data provide reservoir properties such as porosity, hydrocarbon saturation, oil viscosity, and the like, at or near the well bore. The second level of uncertainty arises when one-dimensional reservoir properties are extrapolated to two and three dimensions with the help of geology, seismic (e.g., inversion), and long-term production tests. Errors incurred during extrapolation compound those incurred at the first stage.

The combination of data, together with labarotory measurements such as relative permeability, help construct a reservoir model, either static or dynamic (the latter incorporating fluid-flow characteristics). The reservoir model itself is imperfect because of inherent uncertainties in the data and assumptions that go into building it. The model is a simplified representation of the complex geological/rock/fluid system.

The third level of technical uncertainty is associated with the reserves-estimation process itself. This stage is where shortcomings in estimation procedures compound imperfections in the reservoir model.

Therefore, technical uncertainty is inherent in reserves estimates. As will be noted in the following sections, however, technical uncertainty is not the only factor that affects reserves estimates.

Nondiminishing Uncertainty

A generalization, frequently quoted in the literature, is that as additional data become available with increasing field

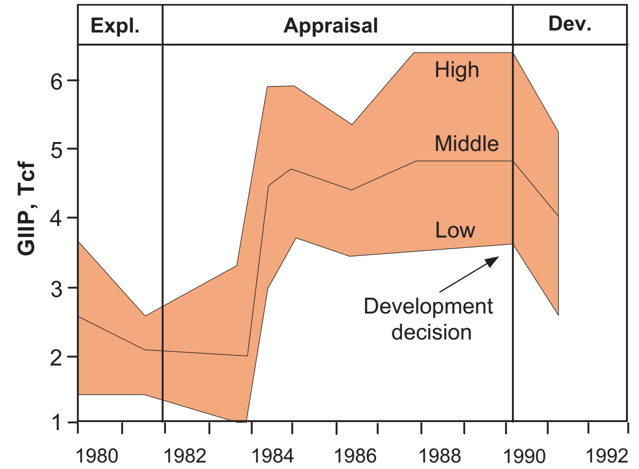

Fig. 4—Uncertainty range in GIIP in unnamed field. Expl.=exploration, Dev.=development.

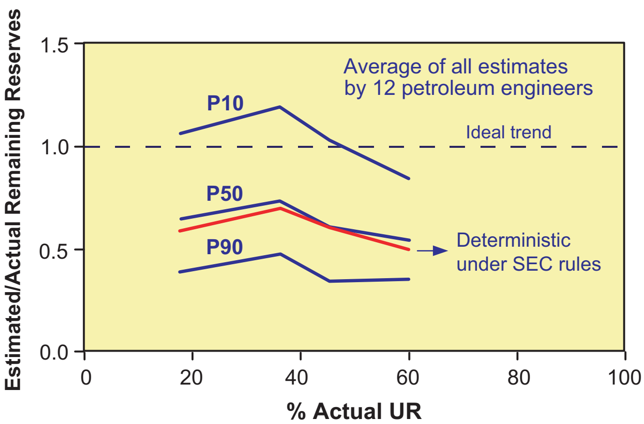

Fig. 5—Reserves estimates in producing well in Colorado.

maturity, uncertainty in ultimate recovery (UR) or reserves becomes smaller. The concept, based on intuition, however, is not supported by evidence. **Fig. 4** is a typical trend of the uncertainty range of estimated gas initially in place (GIIP) for a field in the North Sea (Stoessel 1994). UR histories of many other fields show a similar nondiminishing trend at preproduction stage. Unpublished oil company data point in the same direction.

Less information exists on the behavior of uncertainty range after production, but the general nondiminishing trend appears to hold at this stage also. Results of a study involving 12 experienced petroleum engineers attempting to estimate (remaining) reserves in producing wells in a field in Colorado support this view (Hefner and Thompson 1996). **Fig. 5** shows average results of probabilistic P90, P50, and P10 values (plus the SEC-compliant deterministic value) for one of the wells. The horizontal dashed line defines the ideal situation in which the estimate matches the actual reserves. (The well had reached the economic limit; therefore, the actual reserves could be determined.) It is noted that the P10 to P90 range is nearly constant over time. Similar non-diminishing trends at production stage have been reported from other sources (Thomas 1998; Cronquist 2001).

The foregoing conclusions are consistent with the consensus reached at a European Assn. of Geoscientists & Engineers (EAGE) workshop held in Amsterdam (EAGE 1996). A reasonable explanation for the observed phenomena is that our ability to properly quantify uncertainty, even at the production stage, is rather limited.

Field Reserves Histories

More significant, as far as economic effect, is whether field reserves estimates (expectation values) show consistency over time. Review of field reserves histories from several petroleum provinces indicates that this is generally not the case (Demirmen 2005).

Fig. 6 displays variations in UR estimates for oil over the period 1974 through 2004 for 15 major oil fields on the Norwegian continental shelf (NCS). These are mean values as reported by the operators and occasionally as established by Norwegian Petroleum Directorate. Both pre- and post-production estimates are included. Significant fluctuations in UR over time are evident. The Statfjord field, for example, had its UR estimates slashed substantially 2 years after discovery, but had the estimates upgraded to near-discovery levels many years later. A similar pattern is seen (not reproduced here) when UR values are expressed as percentage of those at production startup time.

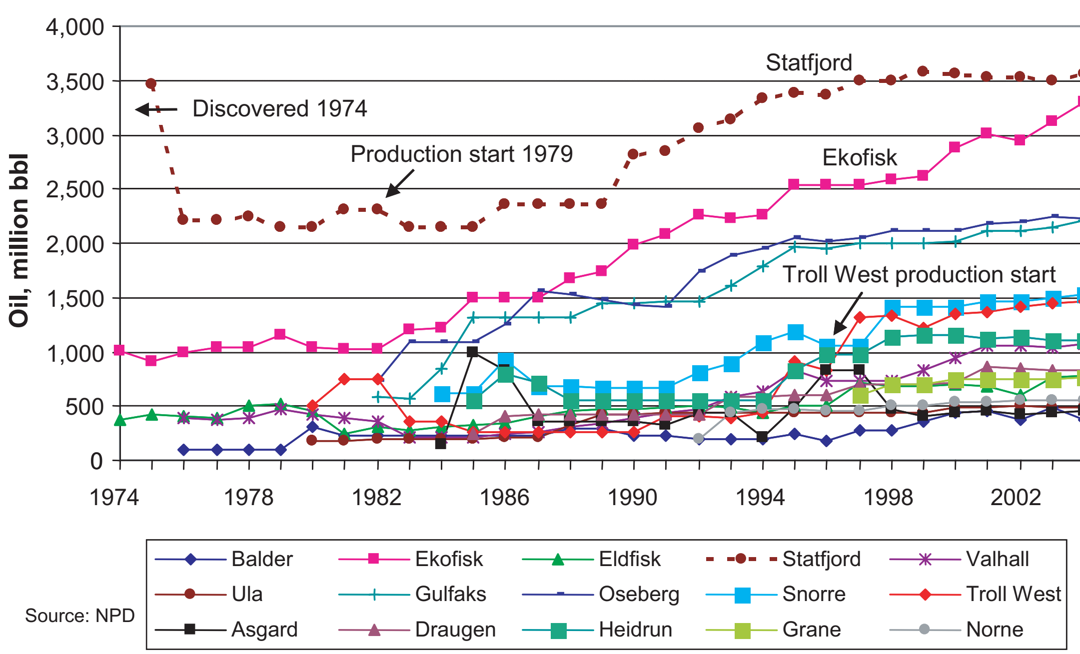

Fig. 6—Changes in UR estimates for oil in major fields on NCS.

Fluctuations similar to those on the NCS are present on the U.K. continental shelf (UKCS) and in the Gulf of Mexico (GOM), both in shallow and deep water. The only difference between the patterns in the North Sea and GOM is the degree of fluctuations and the magnitude of average growth in UR. The most significant fluctuations were noted in post-production estimates in deepwater GOM. This is notwithstanding that deepwater GOM development, occurring relatively late, benefited from better technology compared to shallow-water GOM and the North Sea in general. Although different explanations can be given, it is likely that a relatively low level of field appraisal, driven by cost and early-production considerations, explains the high fluctuations in deepwater GOM.

Economic Damage and Its Ramifications

Post-production fluctuations in expected URs could adversely affect project economics because these volumes are those on which development plans generally are based. Fluctuations may signify that the initial field facilities and infrastructure (F/I) are under- or oversized. Oversized F/I wastes capital. Undersized F/I may require major refurbishments and debottlenecking to handle larger volumes of produced fluids associated with higher reserves. Additional development wells may be needed to supply higher hydrocarbon volumes. Still worse, even without a significant revision in reserves, more producers than originally planned may have to be drilled if the initial reservoir model and production forecasts were optimistic. Pressure-maintenance schemes, if not foreseen at the development planning stage, usually entail a cost penalty if requisite facilities are installed late. The problem is more serious offshore, where modifications to F/I could be rather costly.

Based on a survey of operators and a review of development histories of 25 large fields on the UKCS, it was established that field-development requirements for these fields had changed drastically from 1986 to 1996 **(Table 1)** (Thomas 1998). For the "better fields" (i.e., fields with higher-than-expected reserves), on average, the number of producing wells increased 80%, and water-treatment requirements increased almost 400%. However, per-well UR increased only 7%. Severe drilling and water-treatment constraints that followed required massive expenditures to modify facilities. For the "poorer fields," the situation was worse.

These reserves fluctuations adversely affected profitability—consistent with earlier data from the North Sea (Castle 1985). The problem probably applies to other areas also.

TABLE 1—DEVELOPMENT PLAN CHANGES, UKCS

	"Better Fields" (Reserves Up)		"Poorer Fields" (Reserves Down)	
Number of producing wells	Up	80%	Up	63%
UR/well	Up	7%	Down	50%
Water treat. cap.	Up	385%	Up	154%
Estimated field life	Up	11 yrs	Up	9 yrs

What does the above situation imply? It is known that reserves are intrinsically dynamic, being subject to revisions over time as more data become available. Hence, some variations over time are normal. Furthermore, variations that point to a general pattern of growth are partly a reflection of technology. However, variations, in particular reserves growth, normally should apply to proved reserves, not to expectations. Considering that variations may lead to economic loss, and ideally should be avoided, it can be argued that the industry's record in reserves estimation is less than comforting. For many fields, erratic, even drastic variations in field-UR-prediction histories do not indicate good industry performance.

It also is interesting that in the survey of U.K. operators noted above, 70% of the operators thought reservoir uncertainties had been "reasonably" accounted for in their UR estimates. The record did not match that confidence.

Reserves-Estimation Methods

Reserves-estimation methods are broadly classified as analogy, volumetric, and performance types. Volumetric and performance methods are the more elaborate techniques, and the main difference between the two is the type of data used (i.e., static vs. dynamic) relating to pre- and post-production phases. Compared to performance methods, volumetric techniques generally involve greater errors and uncertainty, and the economic effect can be greater because they generally predate development planning. The choice of methodology depends on development and production maturity, degree of reservoir heterogeneity, and the type, quality, and amount of data. Different estimation methods may yield significantly different results, and reconciliation of the differences may be difficult. If there are wide differences, application of two or more methods may reveal the need for further investigation.

Analogy Method. This estimation method is the simplest, is used for undrilled or sparsely drilled areas, and is based on geologic/reservoir analogy with a nearby producing area. The estimation can be performed on a well-to-well basis or on a unit-recovery basis. The method is reliable to the extent that the analogy is valid. Many companies continue to select analogs to fit their purpose without taking the time and effort to determine the validity of such analogs, some of which are on different continents.

Volumetric Method. The two established volumetric approaches are deterministic and stochastic. In both approaches, mathematical formulas are used to estimate volumes. For oil, UR is a function of the stock-tank oil initially in place (STOIIP) and recovery efficiency (RE), as follows:

$$\mathrm{UR} = \mathrm{STOIIP}\cdot\mathrm{RE}, \quad (1)$$

where

$$\mathrm{STOIIP} = A\cdot h\cdot(\mathrm{n/g})\cdot\phi_i\cdot S_{oi}\cdot b_{oi}\ . \quad (2)$$

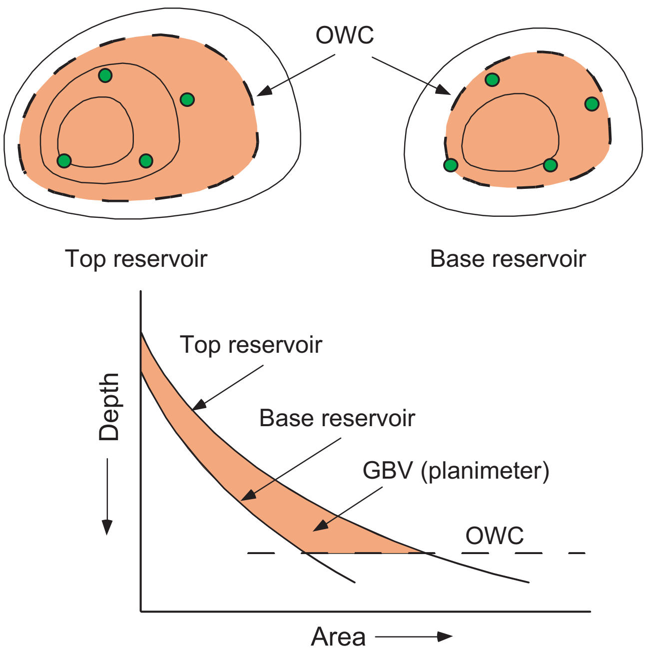

Fig. 7—Estimating GBV.

Equivalent formulas for STOIIP use gross bulk volume (GBV) or net bulk volume (NBV):

$$\text{GBV} = A \cdot h, \quad (3)$$

and

$$\text{NBV} = \text{GBV} \cdot (\text{n/g}). \quad (4)$$

There are comparable formulas for free gas, solution gas, and condensate. RE is determined by analogy, analytically, or by reservoir simulation. For many reservoirs, GBV and RE are the most uncertain parameters in reserves calculations.

In North America, oil reserves at the exploration stage commonly are determined by use of a recovery factor (RF):

$$\text{UR} = A \cdot h_n \cdot \text{RF}, \quad (5)$$

where area, A, is expressed in acres, net reservoir thickness, h_n, in feet, and RF in bbl/acre-ft. RF is determined as follows:

$$\text{RF} = \phi_i \cdot S_{oi} \cdot b_{oi} \cdot \text{RE} \cdot 7{,}758 \quad (6)$$

If at prediscovery stage, a geologic chance factor should be taken into account to risk the estimates. Note: some companies use the RF term to mean what here is called RE.

Deterministic Approach. This approach is the traditional technique for volumetric calculations. In this approach, the input parameters are single values that are considered representative of the reservoir. The corresponding volumetric value obtained also is a single "best-estimate" value. The input data are linked directly to a physical model.

Graphic techniques are commonly used to supplement and improve volumetric calculations. For example, GBV can be obtained by planimetering the top- and base-of-reservoir maps down to the oil/water contact (OWC) or other appropriate fluid contact or level, plotting the areas against vertical depth, and planimetering the area between the top and base of the reservoir on this graph **(Fig. 7).** Multiplication of GBV with average n/g yields NBV. Alternatively, if n/g varies appreciably over the field, a net-sand-thickness vs. area graph should be constructed and planimetered to obtain NBV directly. Likewise, net-oil-sand or equivalent-oil-column vs. area graphs can be used as an aid to calculate STOIIP. Proper attention should be given to geometrical aspects (e.g., fault-trace shift with depth in the case of nonvertical fault planes), and structural contours should be interpolated over highly dipping fault planes and included in calculations.

Mapping software is available to accomplish these tasks by use of digitized data, but the estimator would be well advised to do some of the tasks manually to learn the sensitivity of the calculations. The use of different mapping software packages will almost invariably produce different results; therefore, software should be used with extreme caution. The differences are compounded by structural and stratigraphic complexities.

Recovery efficiencies, while dependent on rock and fluid properties, reservoir-drive mechanisms, and reservoir geometry, should be linked to an actual or notional development plan taking into account well spacing, operations, economics, and contractual constraints. Published recovery efficiencies should not be assigned to new fields without regard to development schemes (particularly well spacing) and per-well economics. Where justified, reserves from incremental projects should be included in estimates under the appropriate resource category shown in Fig. 1.

Quasiprobabilistic "risk-based" and "uncertainty-based" procedures used to derive 1P, 2P, and 3P values on deterministic bases have been suggested, but are not recommended. The temptation to use only the low-case input values for 1P, or only the high-case input values for 3P, should be resisted to prevent gross underestimation and overestimation, respectively. For 1P, the general practice is to define the proved area first, then take the average reservoir properties for this area.

Stochastic Approach. No industry standard exists for stochastic reserves estimation. General practice is to use continuous probability density functions (PDFs) and combine these distributions to generate a PDF for reserves. The input PDFs (e.g., triangular) are combined either analytically (Capen 1992) or by random sampling (Monte Carlo simulation). By central-limit theorem, the resultant (reserves) distribution approaches lognormal, regardless of the type of input variables. Therefore, analytical techniques assume reserves to be lognormal. Monte Carlo simulation requires a large number of iterations for stable results.

Another stochastic technique is the decision-tree approach in which risk-based discrete probabilities are used to estimate reserves. There also is the parametric or three-point technique, which involves approximation and for which input distributions of unspecified type are allowed. There

TABLE 2—RESERVES CALCULATIONS, FIELD KK					
	P90*	P10*	P50	Mean	SD
A (acre) x 1000	1.20	2.90	1.87	1.98	0.70
h (ft)	70	148	102	106	32
n/g	0.68	0.92	0.79	0.80	0.09
ϕ_i	0.18	0.24	0.21	0.21	0.02
S_{oi}	0.64	0.74	0.69	0.69	0.04
b_{oi}	0.75	0.79	0.77	0.77	0.02
RE	0.28	0.40	0.33	0.34	0.05
UR-untruncated, million bbl	22.5	81.8	42.9	48.7	26.2
UR-truncated, million bbl**	33.7	87.9	50.0	56.5	23.7
Probability (UR-tr) ≥	0.68	0.08	0.38	0.29	N/A

** For reservoir properties, P90 and P10 are input values.*
*** Economic cutoff 30 million bbl, plausible max. 200 million bbl.*

are several versions of this technique. Both decision-tree and parametric methods were developed before the advent of modern computer technology and are seldom used in today's corporate environment.

The results from stochastic calculations are summarized generally by a descending (reverse) cumulative probability function commonly known as expectation curve. For risk analysis in exploration, also for developments in high-cost areas, reserves distribution may have to be truncated to honor the economic cutoff. Generally, an upper truncation to honor the maximum plausible reserves is applied also.

Because it provides a range of reserves values with associated probabilities, the stochastic method often is the preferred procedure for volumetric calculations. It enables business decisions in the ever-present uncertainty context, providing a good understanding of risk and potential reward. The methodology first gained acceptance among North Sea operators in the 1960s and 1970s, but is now more widely used.

Example. Stochastic reserves calculations that use the exact analytical solution for oil field "KK" are shown in **Table 2.** For simplicity in calculations, the input variables were assumed independent and lognormally distributed, defined by P90 and P10 parameters. The other parameters, P50, mean, and standard deviation (SD) listed in the table were calculated. The resulting (untruncated) UR distribution, also lognormal, had a relatively narrow spread of P90 at 22.5 million bbl and P10 at 81.8 million bbl, with a mean at 48.7 million bbl.

For this field, the economic cutoff was 30 million bbl and the plausible maximum was 200 million bbl. The original distribution was truncated to honor these constraints. The truncated distribution, which was no longer lognormal, had P90, P10, etc. values that were different from the original values. The expectation curves for the untruncated and truncated distributions in **Fig. 8** show the differences. As expected, the truncated distribution had a smaller dispersion (spread). **Fig. 9** shows the probability density graph of the truncated distribution.

Although truncation increased the P90, P50, P10, and mean values, it also reduced the associated probabilities of success (i.e., the probabilities that volumes would be at least those indicated). P90, for example, increased from 22.5 to 33.7 million bbl, but its probability of success reduced from 0.90 to 0.68. Reserves changes and probabilities of success tend to offset each other.

Note that the truncated values shown in Table 2 and Figs. 8 and 9 are unrisked (i.e., they do not take into account the probability of economic success, P_{es}, corresponding to economic cutoff). The risked values are obtained by multiplying the unrisked values by a P_{es}=0.76. The risked truncated mean, for example, calculates as 43 million bbl. Risked values, in particular the mean, are useful for comparing prospects carrying different risks and different potential rewards.

If KK were an exploration prospect, P_{es} and the probabilities of success shown in Table 2 would be adjusted (lowered) for the chance of geologic success—itself found from consideration of geologic factors such as source rock, reservoir, etc. The risked truncated values would also be affected. (For a discovery, the chance of geologic success is 1).

Performance Methods. These methods are used when there is sufficient pressure and production history to allow

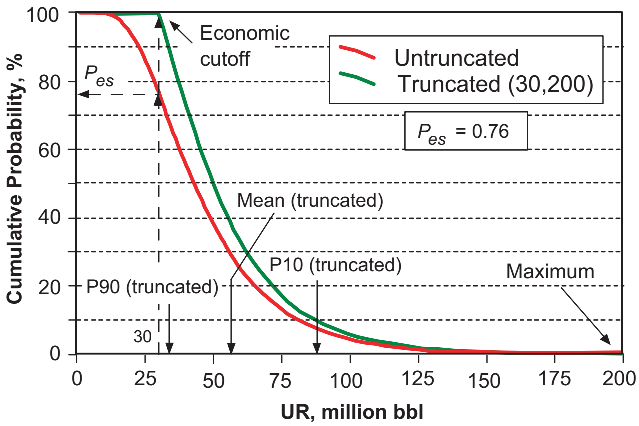

Fig. 8—Expectation curves for field KK.

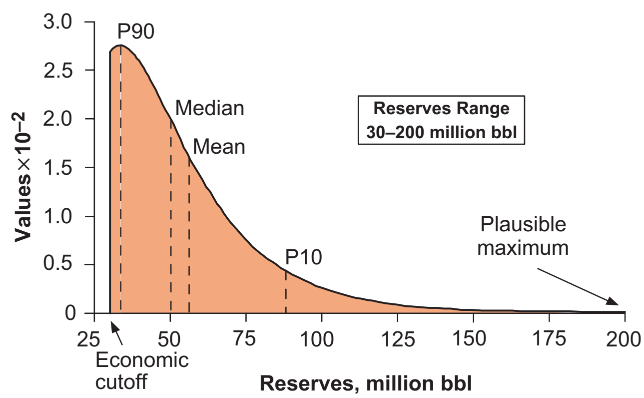

Fig. 9—Truncated distribution, field KK.

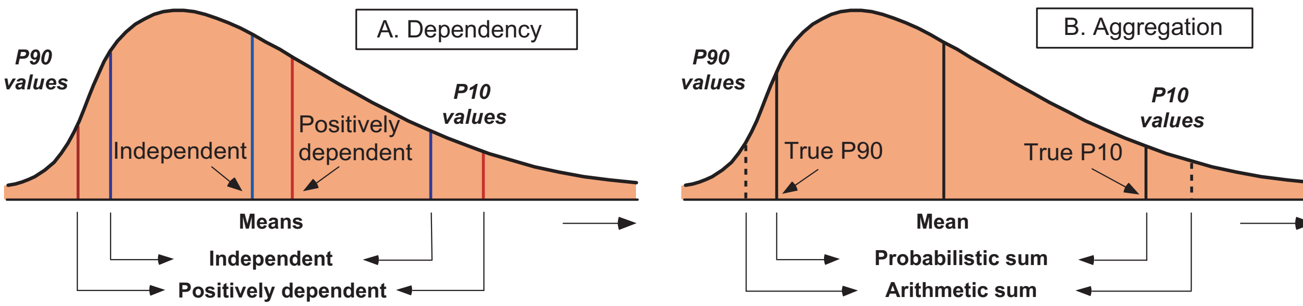

Fig. 10—Dependency (multiplication) and aggregation (summation) issues.

prediction of future performance. Although probabilistic approaches have been applied, the common practice is deterministic.

Decline-Trend Analysis. The analysis refers to estimating reserves on the basis of a reasonably well-defined behavior of a performance characteristic (e.g., production rate or oil cut) as a function of time or cumulative production. The method usually is used for single-well analysis. The trend established from past behavior is extrapolated until the economic limit is reached. The basic assumption is that the trend established in the past will govern the future in a uniform manner. Strictly speaking, such estimates are P50 estimates (i.e., proved plus probable).

Material Balance. This is a conservation-of-matter technique whereby the pressure behavior of the reservoir in response to fluid withdrawal is analyzed in several steps. The fluid properties and pressure history are averaged, treating the reservoir as a tank. For reliable estimates, there must be sufficient pressure and production data (for all fluids) and reliable pressure/volume/temperature data, and the reservoir must have reached semisteady-state conditions.

Reservoir Simulation. This procedure represents the reservoir with a grid, or a set of interconnected tanks, each containing rock and fluid properties. A computer model performs a series of material-balance calculations in different cells, and migration of fluids between adjoining cells is allowed by use of Darcy's flow equation. A development scheme and operating conditions generally are superimposed on the system. For reliable results, a good match between observed history and simulated performance is essential.

Hybrid Methods

In addition to the three reserves estimation methods, there also are hybrid methods that attempt to combine the strengths of deterministic and probabilistic approaches. These emerging techniques are poorly publicized, but they may play a bigger role in future. One such method is the "scenario approach," a semideterministic method in which reservoir uncertainty is depicted by key parameters in a hierarchical manner. Each reservoir attribute is assigned a subjective probability. At the bottom of the hierarchy are reservoir realizations that, linked to suitable development schemes, lead to discrete reserves volumes.

Another emerging methodology can be referred to as a modeling-based stochastic approach. For calculating in-place volumes, this approach is similar to the stochastic volumetric approach except that seismic-depth uncertainties are handled through geostatistical analysis performed on seismic-time and -velocity data. Recovery estimates make a direct linkage between geologic facies and rock and fluid properties, and iterative reservoir-simulation runs are used to derive a PDF for recovery. There seems to be no full application of this method in the literature, but elements of this approach have been proposed (Ovreberg et al. 1992).

Dependencies and Aggregation

The issues of dependency and aggregation, if not addressed, lead to statistical distortions in reserves estimation. The distortions can occur whether the estimation method is deterministic or stochastic, although with the former the distortions are hidden and remedies are impossible, while stochastic methods enable remedies.

One common way that dependency enters reserves estimation is in the calculation of hydrocarbon volumes from multiplication of input data. Statistically, if input variables are positively dependent (correlated), but such dependency is ignored, the P90 value will be overestimated and P10 value will be underestimated, resulting in reduced dispersion as shown in **Fig. 10.** The mean value also will be underestimated. With negative dependency, the effect will be the opposite. Dependencies (e.g., porosity and hydrocarbon saturation, or area and RE) are common in field data; therefore, the problem is not trivial.

The aggregation issue arises when reserves are combined (e.g., adding reserves of several reservoirs to obtain the field total). Statistically, arithmetic addition will distort the results such that P90 values will be underestimated, while P10 values will be overestimated. The mean will be correct. The net effect is too large of a dispersion. The distortion will be mitigated if the component reserves have positive dependencies and aggravated if the dependencies are negative. As the number of summed reserves increases, the difference from the arithmetic sum will become larger, and the probabilistic P10 and P90 values will approach the mean value. The difference between the arithmetic and probabilistic aggregation sometimes is called the portfolio effect.

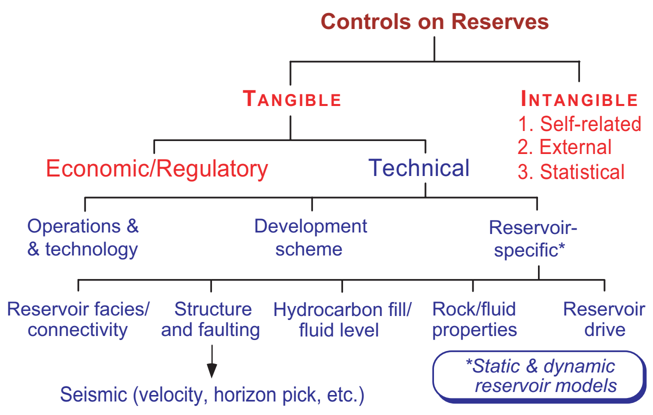

Fig. 11—Factors controlling reserves.

If applicable, aggregation should honor chance of geologic success (risk) and truncation relating to component reserves. This procedure becomes somewhat complicated in the presence of dependencies.

The statistically proper method of aggregating reserves is by probabilistic summation. Reserves aggregation is routine in the industry, and how aggregation is carried out has a large effect on the reliability of reserves estimates. However, a full application of probabilistic summation is not universally endorsed, and there is disagreement in the industry as to how far probabilistic summation should be applied. SPE's December 2005 "mapping" guidance discourages probabilistic summation beyond the field level (Oil and Gas Reserves Committee 2005).

The convenient way to address dependency and aggregation is by Monte Carlo simulation. If independence is assumed, aggregation also can be handled analytically.

Factors Controlling Reserves

As **Fig. 11** shows, reserves estimates are affected by many factors, not necessarily technical, and not all transparent. The major factors are reservoir-specific, which relate to the geological/rock/fluid system and form the basis for reservoir modeling. This is where geoscientific and engineering data enter the estimation process. Development scheme, operations, and technology also play a role. Horizontal drilling and multilateral-completion technology, for example, have boosted reserves significantly in many fields; the Austin chalk trend in south Texas and the Troll West field on the NCS are two well-known examples. Beyond the technical factors, economic and regulatory (including contractual) factors have an overall role in reserves determination.

Technical as well as economic and regulatory factors may be called tangible in the sense that their role is transparent and well acknowledged. Not to be overlooked are intangible factors that are less transparent and not readily acknowledged. One type of intangible factor is self-related, such as experience, competence, integrity, attitude to problem solving, and bias. This point is where professional judgment is important. Bias is a pervasive problem and exacerbates uncertainty.

A second type of intangible factor is external to the evaluator. External factors include some outmoded regulatory rules and management or client pressure to provide the "right numbers."

A third type is statistical in nature, as discussed above. Statistical distortions are one cause of reserves underestimation, and they commonly contribute to reserves growth. The distortions often enter the estimation process without the knowledge of the unwary estimator.

The Road Ahead

The issues outlined above leave little doubt that the industry needs to improve its ability to estimate reserves. The author makes no claim that he has a comprehensive recipe for improvements. Some suggestions that should help are briefly discussed below. The challenge is to enhance the consistency and reliability of reserves estimates early in field history and avoid the surprise element during production.

Optimal Subsurface Appraisal. Poor knowledge of the reservoir, from residual oil saturation to major geologic features such as faulting, can lead to unrealistic reservoir modeling and cause wide fluctuations in reserves estimates. Subsurface appraisal (e.g., outstep drilling, coring, and production testing) could be a significant step for improving our knowledge of the reservoir before or during development. Optimal appraisal signifies early data gathering aimed at reduction of key reservoir uncertainties in a cost-effective manner. To be useful, the appraisal must affect the development decision. Assessing reservoir connectivity (e.g., through pulse or interference testing or seismic inversion) is one of the key objectives of optimization appraisal. Dynamic aspects of the reservoir, however, generally will remain poorly understood until the production phase.

Better Estimation Methods. Unless mandated by regulatory rules, current information technology provides little justification for the deterministic approach, at least at the preproduction phase. Although the advantage of the probabilistic approach, on initial consideration, may not be apparent, the technique addresses uncertainty and allows proper treatment of dependencies and aggregation. This capability is not present with the deterministic approach.

A caveat is in order, however. Dealing with probabilities may cause some evaluators to be less circumspect in their work than otherwise. To the contrary, the probabilistic approach requires much circumspection. The conceptual framework, choice of input distributions, their range, and their dependencies require meticulous thought. Frequently, the endpoints of input distributions are selected too narrowly. With petrophysical data, applying cutoffs could significantly downgrade volumetrics. There should be a conscious effort to avoid bias.

Emerging methodologies such as the scenario and modeling-based stochastic approaches put the geoscientist and the engineer directly in contact with rocks and fluids in the estimation process and can be expected to yield improved reserves estimates.

Attention to Pitfalls. Some of the pitfalls in reserves estimation are of a geoscientific or engineering nature and usually will be avoided by the experienced professional. Still, errors happen and caution is needed. Harrell et al. (2004) describe recurring mistakes in reserves estimates related to mapping and other procedures. One pitfall to avoid in decline-curve analysis, for example, is to aggregate well-decline trends to represent a composite decline for the whole field. Errors in seismic mapping caused for example by polarity reversals and tuning effects should be avoided by seismic modeling, and stringent guidelines should be followed for seismic evidence of hydrocarbons presence. A probabilistic approach should not be considered complete until dependency and aggregation issues are addressed.

Long-Term Outlook. A forward-looking outlook that attempts to foresee and plan for future incremental-recovery projects and technology developments in a life-cycle context could reduce the incidence of reserves-estimate surprises during production. Recoveries from such projects will qualify as unproved reserves and contingent resources.

Look-Back Analysis. Comparison of reserves estimates with actual results on a post-mortem basis will provide valuable learning points. The comparison should include quantitative assessment of bias and accuracy of estimates. Companies can significantly improve estimating abilities by keeping records and tracking estimation performance.

Training. Reserves estimators should be trained toward proficiency in volumetrics, risk assessment, avoidance of bias, and an open-minded attitude with respect to alternative interpretations. Ethical conduct should be cultivated, and the interdisciplinary character of reserves estimation involving geoscientists, engineers, and economists should be emphasized.

Reserves Governance. The management should issue reserves-evaluation guidelines, set peer reviews and audits, and establish a reserves-governance structure.

Conclusion

Reserves estimation is a complex process affected by many factors, not all of them transparent. Uncertainty and subjectivity are inherent in the process. The process, however, must be underpinned by sound geoscientific and engineering practices.

Field histories reveal a mixed record for the industry as far as consistency in reserves estimates. Many fields show wide fluctuations in reserves over time. Fluctuating reserves estimates entail cost penalties even in cases in which estimated recoveries are better than anticipated. Improving reserves reliability is a challenge for the industry and requires a multipoint approach. Efforts to improve reserves-estimation reliability should parallel risk-reduction efforts through use of opportunity portfolios.

There are no quick-fix remedies for reserves-estimation problems. However, certain measures that oil companies can take should provide improvements. When implementing these measures, the proactive role of management cannot be overstated. Depending on circumstances, a probabilistic approach and emerging methodologies generally should be preferred over a deterministic approach.

Acknowledgments

The author is indebted to Chapman Cronquist, Ron Harrell, and Ed Capen for reading the draft manuscript and making valuable suggestions. Thanks also are due to Ed Capen for extended discussions on reserves issues.

Nomenclature

A = Area (oil zone)
b_{oi} = Initial oil shrinkage factor ($=1/B_{oi}$)
B_{oi} = Initial oil formation volume factor
h = Thickness (gross, oil zone)
h_n = Net thickness (oil zone)
n/g = Net-to-gross thickness ratio (oil zone)
P_{es} = Probability of economic success
S_{oi} = Initial oil saturation
ϕ_i = Initial porosity (oil zone)

References

Capen, E.C. 1992. Dealing with Exploration Uncertainties. In *The Business of Petroleum Exploration,* ed. R. Steinmetz, Tulsa: American Assn. Petroleum Geologists, 29–61.

Castle, G.R. 1985. Assessment of North Sea Field Performance. *Petroleum Economist,* October: 358–359.

Cronquist, C. 2001. *Estimation and Classification of Reserves of Crude Oil, Natural Gas, and Condensate.* Richardson, Texas: Society of Petroleum Engineers. 416.

Demirmen, F. 2005. Reliability and Uncertainty in Reserves: How and Why the Industry Fails, and a Vision for Improvement. Paper SPE 94680 presented at the SPE Hydrocarbon Economics & Evaluation Symposium, Dallas, 3–5 April. DOI: 10.2118/94680-MS.

EAGE 1996. Workshop Report: Uncertainty in Reserve Estimates. *Petroleum Geoscience* **2** (4): 351–352.

Harrell, D.R., Hodgin, J.E., and Wagenhofer, T. 2004. Oil and Gas Reserves Estimates: Recurring Mistakes and Errors. Paper SPE 91069 presented at the SPE Annual Technical Conference & Exhibition, Houston, 28–29 September. DOI: 10.2118/91069-MS.

Hefner, J.M., and Thompson, R.S. 1996. A Comparison of Probabilistic and Deterministic Reserve Estimates: A Case Study. *SPERE* **11** (2): 43–47. Paper SPE 26388. DOI: 10.2118/26388-PA.

Oil and Gas Reserves Committee Mapping Subcommittee Final Report—December 2005: Comparison of Selected Reserves and Resource Classifications and Associated Definitions. 2005. Richardson, Texas: Society of Petroleum Engineers. http://www.spe.org/web/ogr/OGR_Mapping_Final_Report_15Dec05.pdf. (Accessed 2 April 2007.)

Ovreberg, O., Damsleth, E., and Haldorsen, H.H. 1992. Putting Error Bars on Reservoir Engineering Forecasts. *JPT* **44** (6): 732–738. Paper SPE 20512. DOI: 10.2118/20512-PA.

Petroleum Reserves Definitions. 1997. Richardson, Texas: Society of Petroleum Engineers. http://www.spe.org/spe/jsp/basic/0,2396,1104_12169_0,00.html. (Accessed on 14 February 2007.)

Petroleum Resources Definitions. 2000. Richardson, Texas: Society of Petroleum Engineers. http://www.spe.org/spe/jsp/basic/0,2396,1104_12171_0,00.html. (Accessed on 14 February 2007.)

Petroleum Reserves and Resources Classification, Definitions and Guidelines (draft). 2006 Richardson, Texas: Society of Petroleum Engineers. http://www.spe.org/spe/jsp/basic/0,,1104_5806693,00.html. (Accessed on 14 February 2007.)

Stoessel, E.T. 1994. The Alliance between Uncertainty and Credibility. *The Leading Edge* **13** (4): 270–272.

Thomas, J.M. 1998. Estimation of Ultimate Recovery for UK Oil Fields: The Results of the DTI Questionnaire and a Historical Analysis. *Petroleum Geoscience* **4** (2): 157–161, followed by "Discussion" by F. Demirmen and the author, **5** (1): 29–30 (1999).

JPT