A SYSTEMATIC APPROACH TO RESERVES AUDITING, TRACKING

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Introduction

A major source of confusion in our industry is the different perceptions of reserves, not only within the same company -- an explorationist's estimate is usually quite different from an engineer's -- but also at different stages of development of the hydrocarbon resource. This commonly bemuses managers and outsiders, particularly bankers, who are accustomed to relatively straight-forward inventory control in other industries.

Similarly reserves reports for an area omit hydrocarbon volumes that are considered uneconomic under existing fiscal conditions, e.g. sub-commercial discoveries. Strictly speaking, sub-commercial accumulations should be excluded from the reports, however, these volumes represent potential future value to a company and are essential for, among other things, determining the fair market value of an area, the design and positioning of surface facilities and allocation of human as well as capital resources.

If logically presented, inclusion of potential hydrocarbons with reserves data provide managers, government officials and lenders with a clearer picture of an area's known and potential value. Our proposed method of reporting the total hydrocarbon resource of an area at different stages of discovery and development (Table 1) is consistent with the current classifications recognized by SEC, SPE, WPC, AAPG and Government regulatory bodies, and this audit report methodology is now being used by a number of different Governments and some major oil companies. This system was actually precipitated by a senior Government official asking one of the authors "why does my Energy Ministry continuously report oil and gas 'discoveries', but there is no change to my country's anticipated production?"

In addition to providing a clear summary of total hydrocarbons within a geographical area or business unit, our method can accommodate any method of calculating the resource volume from single-point "most likely" input values, through multi-point values (i.e. proved, probable, possible) to the continuous function or expectation curve.

Discussion

Reserves are commonly defined as "the economically recoverable portion of the hydrocarbon resource". During assessment and deveolpemnt of a field, beginning with subsurface maps of an undrilled structure and ending with the depletion of the field, the original resoiurce, called "oil or gas-in-place" or "hydrocarbons-in-place" (HIP), does **not** change -- only our perception of the reserves portion of the volume varies, usually with changes in the viability of extracting the hydrocarbons, commonly due to fluctuations in the commodity (oil and gas) prices, and the technical/mechanical efficiency of producing the hydrocarbons.

In other words, the variables affecting recovery factor, and thus reserves, are principally technical and economic. These variables are often independent and imply that a two-dimensional matrix ("spreadsheet") could be used for description (see Table 1).

Table 1. Classification of hydrocarbon volumes

Reserves Category	**Field** Oil Gas NGL	**Discovery** Oil Gas NGL	**Prospect** Oil Gas NGL	**Lead** Oil Gas NGL
Production (cumulative)	F1	-	-	-
Developed	F2	-	-	-
Undeveloped	F3	D3	-	-
Potential **(conventional methods)**	F4	D4	P4	L4
Potential **(unconventional methods)**	F5	D5	P5	L5
HIP	F6	D6	P6	L6

Categories in Table 1 describe the same resource but reflect uncertainties inherent in the assessment. The level of uncertainty is highest before the prospect is drilled and is reduced with the increase in data. It is the uncertainty and risk attached each category or cell in the table that is used to classify volumes. Although there is no scale, the horizontal axis is a measure of time, increasing from right to left, and reflects the increasing amount of data available as an area is mapped, drilled and either abandoned or developed.

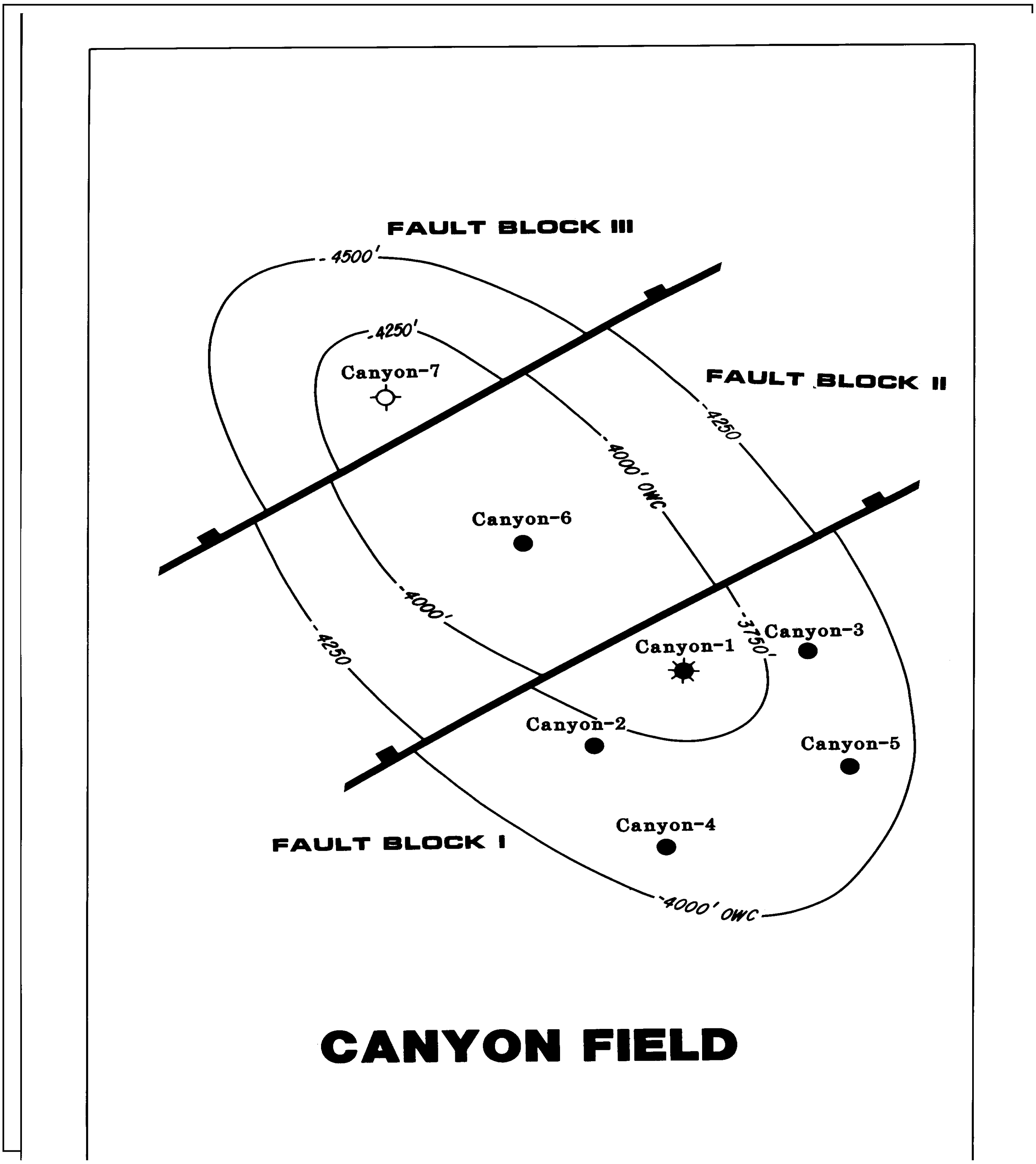
By classifying volumes of oil, gas or natural gas liquids (NGL) according to the degree of risk and uncertainty and assigning them to cells in the table, a reserves audit report (Table 2) can be readily prepared which provides a comprehensive tabulation of hydrocarbon volumes at any stage of exploration or development.

Table 2. Reserves Audit Report

	OIL (MMBbls)	**NGL (MMBbls)**	**GAS (BCF)**
Cumulative Production (F1)			
Developed Reserves (F2)			
Undeveloped Reserves in developed fields (F3)			
Undeveloped Reserves in undeveloped discoveries and fields (D3)			
Total Reserves (F2+F3+D3)			
Potential reserves with proven technology in producing fields (F4)			
Potential reserves with unproven technology in producing fields (F5)			
Potential reserves in undeveloped discoveries (D4)			
Potential reserves in prospects and leads (P4+L4+P5+L5)			
Total Potential reserves			
HIP in producing fields (F6)			
HIP in undeveloped discoveries (D6)			
HIP in prospects and leads (P6+L6)			
Total HIP (F6+D6+P6+L6)			

HISTORY OF THE 'CANYON' FIELD

In this example, for simplicity, the "Canyon" structure is comprised of three fault blocks and occupies nearly the entire concession area. The same methods apply, however, to large concessions containing multiple undrilled structures, producing fields and sub-commercial discoveries.



Let's look at a hypothetical concession history, divided into the following time segments:

- Conceptual, play evaluation
- Leads and Prospects
- Drilled prospect - discovery
- Appraised discovery
- Field delineation and development
- Field extensions
- Pressure maintenance/waterflood
- Improved recovery - EOR

Conceptual Play Evaluation and Leads

The exploration department evaluates the concession and although seismic coverage is sparse and closure is yet to be confirmed, determines that a lead exists, that further exploration is warranted, and preliminary maps are then made. Respective values for reserves and in-place numbers are placed in cells L4 and L6.

Reserves Category	**Field** Oil Gas NGL	**Discovery** Oil Gas NGL	**Prospect** Oil Gas NGL	**Lead** Oil Gas NGL
Production (cumulative)	-	-	-	-
Developed	-	-	-	-
Undeveloped	-	-	-	-
Potential **(conventional methods)**	-	-	-	XXXX
Potential **(unconventional methods)**	-	-	-	-
HIP	-	-	-	XXXX

Each time a number is added to the table, revised or moved from one cell to another, it should be conscientiously referenced with footnotes which then become an integral part of the table. The footnotes are important in following the history and derivation of the reserves numbers. A good practice is to keep a separate binder as a detailed reference to back up all the data. For instance, structure maps on which areal extent and closure were measured should be contained in the file, as should logs and log analyses that are the basis for gas/oil and oil/water contacts, porosity and water saturation, PVT analyses and any other data which serve as a background for estimates. Workers assigned to the project in later years may not always agree with previous analyses, but there should be no doubt in their mind as to where the numbers came from.

In practice, it is usually more informative and realistic to carry potential reserves as a range of values, i.e. 235 - 285 MMbo, and to round the numbers off to the nearest five or ten million barrels for hydrocarbons in the "Discovery", "Prospect" or "Leads" categories.

Prospect

A comprehensive seismic program is conducted and integrated with other available data. Down-dip limits of the structure are delineated, the feature is mapped as having four-way dip closure and two normal faults are identified. The structure is now sufficiently well defined to be designated a prospect, and values in L4 and L6 are revised and moved to P4 and P6 respectively.

Reserves Category	**Field** Oil Gas NGL	**Discovery** Oil Gas NGL	**Prospect** Oil Gas NGL	**Lead** Oil Gas NGL
Production (cumulative)	-	-	-	-
Developed	-	-	-	-
Undeveloped	-	-	-	-
Potential **(conventional methods)**	-	-	XXXX	-
Potential **(unconventional methods)**	-	-	-	-
HIP	-	-	XXXX	-

Often, when a large seismic program is carried out, more than one lead is identified, thus some values would remain in the "Leads" category. For simplicity, we will ignore this situation.

Drilled Prospect - Discovery

Wildcat well Canyon-1 is drilled and although some isolated gas sands are encountered in a shallow section, the well unexpectantly encounters a thick oil-bearing reservoir and tests oil at significant rates. Commerciality is yet to be determined. Based on areal distribution of the reservoirs and log analysis, Fault Block I volumetric estimates can be moved to D4 and D6.

Reserves Category	**Field** Oil Gas NGL	**Discovery** Oil Gas NGL	**Prospect** Oil Gas NGL	**Lead** Oil Gas NGL
Production (cumulative)	-	-	-	-
Developed	-	-	-	-
Undeveloped	-	-	-	-
Potential (conventional methods)	-	XXXX	-	-
Potential (unconventional methods)	-	-	-	-
HIP	-	XXXX	-	-

Appraisal

Appraisal wells Canyon #2 and Canyon #3 are drilled. The results of these wells are sufficient to encourage the operator to deem the prospect to be a commercial oil field. Volumes in the drainage areas of the three wells can now be assigned to D3 (undeveloped). The remaining hydrocarbons in Fault Block I are potentially recoverable and are assigned to D4. A gas sand (tested) was also intercepted by these wells, but as there is no ready market nor plan to produce the gas, these are also placed in D4. Potential reserves in Fault Blocks II, III remain in cell P4.

Reserves Category	**Field** Oil Gas NGL	**Discovery** Oil Gas NGL	**Prospect** Oil Gas NGL	**Lead** Oil Gas NGL
Production (cumulative)	-	-	-	-
Developed	-	-	-	-
Undeveloped	-	XXXX	-	-
Potential (conventional methods)	-	XXXX	XXXX	-
Potential (unconventional methods)	-	-	-	-
HIP	-	XXXX	XXXX	-

Field Delineation and Development

Plan of Development for the Canyon field (Fault Block I) is approved by management, partners and Government regulatory bodies. Blocks II, III are not considered for development at this stage. Oil volumes can now be transferred to cells F3, F4, and F6, while the gas categories are unchanged (D4) as gas commerciality is yet to be determined.

Field Extensions

Fault Block I is developed (development wells Canyon #4 and #5 are drilled) and placed on production (volumes in F1, F2 and F6). Fault Block II is successfully appraised by well Canyon # 6, but not yet developed (volumes in F3 and F6). Block III is still undrilled (volumes in P4 and P6). Gas is still unchanged.

Reserves Category	**Field** **Oil Gas NGL**	**Discovery** **Oil Gas NGL**	**Prospect** **Oil Gas NGL**	**Lead** **Oil Gas NGL**
Production (cumulative)	XXXX	-	-	-
Developed	XXXX	-	-	-
Undeveloped	XXXX	-	-	-
Potential **(conventional methods)**	XXXX	XXXX	XXXX	-
Potential **(unconventional methods)**	-	-	-	-
HIP	XXXX	XXXX	XXXX	-

Pressure Maintenance/Waterflood

Reservoir simulation indicates that water injection could increase ultimate recovery. These could be placed in the D4 or P4 categories. Infill drilling with gas lift is also deemed to be able to improve recovery. As a waterflood requires some capital expenditure, no approval can be obtained until the next budget year. Since some infill drilling is currently economic, (and some not!), F3 and F4 volumes are calculated. Also, it is believed that some tertiary EOR may also improve ultimate recovery, and P5 volumes are calculated accordingly

A pilot waterflood is approved for Block II. Some of the water injection volumes can then be transferred from F4 to F3. A further appraisal well, Canyon #7 proves Block III to be dry (below OWC), so these volumes are deleted.

Reserves Category	**Field** **Oil Gas NGL**	**Discovery** **Oil Gas NGL**	**Prospect** **Oil Gas NGL**	**Lead** **Oil Gas NGL**
Production (cumulative)	XXXX	-	-	-
Developed	XXXX	-	-	-
Undeveloped	XXXX	-	-	-
Potential **(conventional methods)**	XXXX	XXXX	XXXX	-
Potential **(unconventional methods)**	-	-	XXXX	-
HIP	XXXX	XXXX	XXXX	-

Improved Recovery - EOR

Laboratory screening tests as well as operational conditions (source availability,etc) confirm the suitability of the tertiary EOR, hence the P5 volume can be transferred to F5. The pilot water injection wells are drilled, so some volumes can be transferred from F3 to F2, as can some volumes influenced by infill drilling and a planned (but not yet approved) gas lift project (some gas volumes can be moved from D4 to F3).

Reserves Category	Field Oil Gas NGL	Discovery Oil Gas NGL	Prospect Oil Gas NGL	Lead Oil Gas NGL
Production (cumulative)	XXXX	-	-	-
Developed	XXXX	-	-	-
Undeveloped	XXXX	XXXX	-	-
Potential (conventional methods)	XXXX	XXXX	XXXX	-
Potential (unconventional methods)	XXXX	-	-	-
HIP	XXXX	XXXX	XXXX	-

There is an overall rise in oil prices which is thought to be relatively consistent, causing further infill wells to become economic (some further volumes are then moved from F4 to F3). The gas lift scheme is approved and implemented so gas volumes can be moved from F3 to F2. The waterflood pilot is successful and a full scale flood is planned, approved and started (further F3 can be moved to F2). Thus more volumes can be transferred from F4 to F3. A pilot EOR is approved and begun, although this does not allow any transfer of volumes as the method is not deemed to be relatively certain of technical success (remains in F5).

Reserves Category	Field Oil Gas NGL	Discovery Oil Gas NGL	Prospect Oil Gas NGL	Lead Oil Gas NGL
Production (cumulative)	XXXX	-	-	-
Developed	XXXX	-	-	-
Undeveloped	XXXX	XXXX	-	-
Potential (conventional methods)	XXXX	XXXX	XXXX	-
Potential (unconventional methods)	XXXX	-	-	-
HIP	XXXX	XXXX	XXXX	-

Changes in Fiscal Terms

The fiscal terms are changed by the host government, which means that further infill drilling is not economically justifiable (remaining F3 is moved to F4). Also the pilot EOR is technically successful, but the change in terms means that a full scale project is not viable, so volumes are transferred from F5 to F4

Reserves Category	Field Oil Gas NGL	Discovery Oil Gas NGL	Prospect Oil Gas NGL	Lead Oil Gas NGL
Production (cumulative)	XXXX	-	-	-

Developed	XXXX	-	-	-
Undeveloped	-	XXXX	-	-
Potential **(conventional methods)**	XXXX	XXXX	XXXX	-
Potential **(unconventional methods)**	-	-	-	-
HIP	XXXX	XXXX	XXXX	-

Field Abandonment

Canyon field is no longer economic to keep on production (F2=0), but some further infill wells may be economic if the price increases substantially (retain in F4), however the EOR is not viable even if the price varies substantially (drop from F4). Of course these economics will change even further if the field is temporarily abandoned, as some capital will be needed for further start-up. If this investment is deemed to be too expensive, only F1 and F6 are retained for the Canyon field

Reserves Category	**Field** **Oil Gas NGL**	**Discovery** **Oil Gas NGL**	**Prospect** **Oil Gas NGL**	**Lead** **Oil Gas NGL**
Production (cumulative)	XXXX	-	-	-
Developed	-	-	-	-
Undeveloped	-	XXXX	-	-
Potential **(conventional methods)**	XXXX	XXXX	XXXX	-
Potential **(unconventional methods)**	-	-	-	-
HIP	XXXX	XXXX	XXXX	-

Conclusion

We have presented a relatively simple reserves tracking and auditing method which could be used by different organizations for different reasons. This method is an attempt to resolve the problem of inconsistencies of reserves evaluations between different disciplines and elements of uncertainty, with either deterministic or probabilistic procedures equally valid.

THE NOMENCLATURE

Petroleum resource

This term encompasses all the commonly used distinctions such as originally or initially in place, ultimate recovery, cumulative production, reserves,etc. but has no economic constraints.

Reserves

The recommended classification system contains three reserves categories: F2, F3, D3, representing resources whose development and production are expected to generate an acceptable revenue and contribute to the participating companies' cash flow. When the resources are not expected to be developed or produced within the current concession or contract life, this should be noted but should not affect the reserves volume. However this is a controversial issue, with different organizations having different interpretations.

The split into developed and undeveloped reserves is important for corporate strategic planning. The developed portion represents the 'liquid' assets of the Company which may be thought of as 'bankable' assets since they are expected to be recoverable without major capital expenditure, whereas the undeveloped reserves normally form the basis for drilling and engineering activity within the medium-term (up to five years).

A further sub-division of the developed portion into producing or producible and unproducible portions could be considered. The producible portion would represent the resource which could be expected to be recovered from completion intervals which are presently open or able to be opened by wireline work or the opening of valves. The main problem with a producible category is that future hardware failures should be accounted for that may render the interval unproducible - and these can only be statistically estimated. Thus, the producible category cannot be accurately defined.

[but it can be assumed that remedial work will be undertaken provided that financial benefit of work outweighs the costs]

Field

This category should be used for all hydrocarbon resources within a field from which there has been continuous controlled production (i.e. any production which cannot be classified as a production test or a blow-out) or where development activity is approved (i.e. development plan and budget has been approved by the operating companny and the necessary Government bodies). This category will therefore incorporate currently producing, closed-in or abandoned reservoirs and may also incorporate reservoirs under development and unappraised reservoirs, providing they lie within the field boundaries (which should be defined both areally and vertically).

Abandoned reservoirs should normally only carry F1 and F6 resources, but they must be included to ensure that immovable oil or gas is not disregarded if economic conditions change or if the implementation of new technologies becomes applicable.

A considerable matter of debate in some countries is whether unpenetrated reservoirs immediately adjacent to petroleum-bearing reservoirs (e.g. in the next fault block) and those immediately below the deepest petroleum-bearing reservoir may be considered to lie within the field boundary.

Other alternatives could be existing field and producing field.

Discovery

This category can contain such widely differing resources as the reservoir with a one (1) meter oil column (which may only be evaluated under D5) in a low-cost onshore environment, to a potentially very large resource requiring extensive appraisal (which may have D4, D5, and D6 volumes) such as a deep water gas discovery that contains a high percentage of CO_2.

Options considered were new discovery, unappraised discovery, undeveloped discovery, unappraised accumulation, undeveloped accumulation, minor accumulation, unappraised field, prospective field and undeveloped field.

Prospect

This category represents all hydrocarbon resources, beyond existing field boundaries, where the presence of petroleum has been demonstrated by the drilling of a well. This term was selected since it are commonly used by explorationists the world over.

Lead

This category contains all hydrocarbon resources, beyond existing field boundaries, where there is a chance of the existence of the trapping of hydrocarbons, demonstrated by accepted geologic and geophysical methods.

Another category - "play" - could have also been considered, but could cause more confusion than is warranted, as it is usually conceptual in nature.

Potential

The recommended classification system contains five potential categories: F4, F5, D4, P4 and L4. Alternative descriptions of potential reserves could be "speculative" reserves or "sub-economic" reserves. The main confusing feature is the use of the word "reserves", which by definition should represent an economic resource. The term "scope for recovery" has been used by at least one large organization to overcome this terminology dilemma.

The split into proved techniques and unproved techniques is again primarily important for development of corporate strategies. The proved techniques portion represents processes and methods which have been a technical and economical success under similar circumstances elsewhere in the world. This leads to the terms: 'exploration potential' for undrilled resources, since the economics are uncertain (P4 and L4); 'appraisal potential' where additional resources need to be found to make development viable (D4 and part of F4); 'infill scope' in fields where new drainage points are not currently economic (part of F4) and 'improved recovery scope' for the use of established techniques whose implementation is not yet certain or not yet demonstrated to be economic (also part of F4). Potential exploration and appraisal volumes are generally discounted by the application of a "chance" factor (often denoted by COS - probability or chance of success), reflecting the likelihood of a proven procedure being a technical success in the candidate reservoir.

The unproved techniques portion represents improved recovery by a process which has not yet been demonstrated to be technically feasible and to economically generate additional recovery. This not only includes the well known 'EOR' processes, but also operational methods such as improved recovery made possible by horizontal wells, floating production systems, etc. This is normally only relevant to oil resources, where it leads to the term 'EOR potential' (F5). This category will always be discounted by the application of a risk factor, reflecting the likelihood of the process or method being a technical success.

Care is required in deciding what volumes can reasonably be carried as 'potential', since an almost limitless number of infill drainage points or improved recovery processes could be considered. It is recommended to only consider research and technological breakthroughs which are currently believed to have good prospects for commercial application with the next 10 - 15 years.

Hydrocarbons-in-Place (HIP)

This is the ultimate resource, included in the classification system to indicate the volume against which cumulative production, reserves and potential recoverable volumes must be compared to assess the relative efficiency of different recovery processes in various reservoirs. There are four HIP categories in the recommended system: F6,D6, P6 and L6.

IDENTIFIERS

Method of calculation

Since there will always be uncertainty in the basic data and resultant volume estimates, it is recommended to use the expectation curve for categories F2 to L6. Single-point values are recommended for cumulative production (category F1) since it has to be reported as such for fiscalisation purposes.

Two key values are commonly extracted from an expectation curve. They are the proved and expectation volumes. It is recommended to always report these key values and to use proved volumes for contractual negotiations and expectation volumes for company planning.

Level of calculation

Petroleum resource volume calculations should normally be performed at the discrete reservoir level. However many organizations operate fields consisting of hundreds of reservoirs. Thus, for reporting purposes, and in order to reduce results to a manageable level for analysis and comparison, it is recommended to use the field level (i.e. productive field, prospective field, prospect or lead) as a standard reference level.

Type of petroleum

Reports to the SEC require three petroleum types to be recognized as they appear at surface: oil or crude oil, natural gas liquids (NGL) and gas or natural gas. In addition, gas reserves are to be reported for quantities that are either contracted to sale or can be considered as such. Thus, a split of gas volumes into committed and uncommitted is often required. These identifiers must therefore be used in any recommended audit system.

Optimum management of petroleum resources often requires further division of the above categories. In the interests of consistency it is recommended to use only the following divisions as appropriate: gas into solution/dissolved gas or free/gascap/dome gas, associated gas or non-associated gas, and dry gas or wet gas; NGL into condensate or LPG; and oil into extra heavy, heavy, medium, light or volatile based on its API gravity. All petroleum resources may be considered sweet or sour based on their sulphur content.

Recovery process

There is an almost limitless number of terms describing the processes which are occurring in the reservoir, such as: natural, assisted, enhanced, thermal, primary, secondary, etc. A project such as infill drilling, water injection etc., initiated at any particular stage of development, may make use of one or more of these recovery processes. Thus, selection of an appropriate identifier is left to the discretion of the company. However, in an attempt to simplify matters it is recommended to use only the terms primary and improved recovery to describe the recovery process.

When a project can be demonstrated to be technically and economically feasible, the reserves volume should be amended to include the estimated recovery from the project. All other projects should be evaluated as part of the 'potential' calculations. Thus, an infill drilling project would be identified as primary recovery reserves if it was economic and 'potential' primary reserves if it was not economic. Similarly, a water injection project would be identified as improved recovery reserves if it was underway or firmly planned and 'potential' reserves by improved recovery if it was a possible extension to an existing project or new project.

AFTER THIS IS JUST IDLE THOUGHTS!!!!!!

DEFINITIONS AND SPECIAL CASES

A comprehensive set of definitions should follow the wording used by the World Petroleum Congress study group if appropriate.

Petroleum resource volume estimation can be complicated by factors governing the concession agreement. It is recommended that volumes are always estimated for total resources in all reservoirs, initially ignoring any division of the resource imposed by production sharing contracts, taxes, unitization agreements and cases where the operating company only holds the rights to the oil and not the gas resource. However, these divisions must be noted and accounted for in any summary, presentation or comparison of volumes.

Petroleum resource volume estimation can also be complicated by the processes used in development and production, such as the installation of artificial lift, well stimulation production methods, etc. Where such processes exist or are firmly planned they should be accounted for in assessing both developed and undeveloped reserves. Where such processes are not firmly planned, but can be demonstrated to be economic, they should be accounted for in assessing undeveloped reserves. Where such processes are not expected to be economic they may be accounted for in assessing the potential recovery.

REPORTING REQUIREMENTS

It is therefore recommended to compile reports, preferably on a field basis, giving the basic data, the way it has been interpreted and processed and the resultant volumes. Where subsequent small changes are made, a changes report should be compiled. After several years of small changes or following a major review, a new full field report should be issued.

COMPARISON WITH OTHER SYSTEMS

The World Petroleum Congress (WPC) set up a study group in 1980, which presented an interim report on classification and nomenclature systems for petroleum and petroleum resources in 1983 and a final report in 1987. They define proved, probable and possible categories of reserves, with: 'proved' having a sufficient degree of probability to suggest their existence; 'probable' having a reasonable degree of probability, but not sufficient to be classified as 'proved; and 'possible' having only a moderate degree of probability. Where it is difficult to distinguish between 'probable' and 'possible' reserves, the term 'unproved reserves' may be applied and although not specifically mentioned, resources which may be recovered as a result of advances in technology, the implementation of improved recovery schemes or improved economic outlook could be accommodated in this category. A category of 'undiscovered potential recovery' is defined to cover exploration and appraisal prospects and leads, along with usual categories of petroleum-in-place (HIP) and developed/undeveloped reserves fractions.

The use of expectation curves, under situations where more sophisticated techniques are required, and the link with proved/probable/possible is qualitatively discussed. No quantitative link is made and no specific guidance on when to use each system is given. The WPC state that aggregation of different categories is allowed, providing all the uncertainties have been taken into account.

The Society of Petroleum Engineers (SPE) established a committee in 1984, which issued definitions in 1987. They present a system which is similar to the WPC system, but not as extensive since it is only concerned with reserves (i.e. it does not include the 'petroleum-in-place' and 'undiscovered potential recovery' categories). Their definitions of proved probable and possible reserves are based on data being demonstrated with: a reasonable degree of certainty for 'proved'; similar to 'proved' but lacking the certainty required to classify it as 'proved' for probable; and less complete/conclusive than used in 'probable' for 'possible'. The SPE conclude that probabilities should not form part of the definitions since they require subjective judgement and could unduly complicate the definitions. They also propose a more rigid economic criteria for proved reserves, based on current prices and costs. Finally, it is recommended not to add the categories, since they do not carry equal risk or value.

In a survey of reserves categories/definitions employed by government/regulatory bodies, the majority were found to use the proved, probable, possible and potential categories as proposed by the WPC. Only four out of 25 linked these categories to cumulative probability levels, with Austria, Canada and Netherlands taking a 90% cumulative probability to define proved reserves and the Australian Minerals and Energy Council taking 93%. The UK now takes a 90% cumulative probability level to define proved reserves. Some companies use the value of 85% which has been accepted by external auditors as giving results which are broadly in line with the SEC definition of proved reserves (pers. comm.).

The probabilistic approach is preferred since it yields a probability distributions, from which 'proved' and 'expected' values can be derived in a consistent and well-defined manner. Whilst the calculated distribution is subjective, this is true for all reserves assessments. However, the probabilistic approach is the only way to properly quantify the range of uncertainty involved and is certainly considered superior to the vague and non-interrelatable proved, probable and possible categories. In addition, the categories proposed in this report are considered to be more extensive and of greater practical use than those proposed by the WPC, since they establish a boundary between volumes which are presently considered to be economically recoverable (reserves) and those which are not and since they use the sub-divisions: lead, prospect, prospective, field and productive field which can be related to planned activity.

Whilst there is a choice of acceptance or rejection of SPE and WPC definitions, there is an obligation to report proved and proved developed reserves in line with SEC definitions. The definitions recommended in this report are in line with those of the SEC except on the following points:

a) The SEC require 'reasonable certainty', whereas this report takes 'the weighted average of the most probable third of the expectation curve, often approximated by the 85 percentile value'.

b) The SEC allow ' prices and costs as the date the estimate is made. Prices include changes provided by contractual arrangement', whereas this report takes 'current projections of future prices and costs'.

c) The SEC require reserves to be 'economically recoverable' whereas this report requires 'an acceptable real term earning power'.

d) The SEC require 'economic producibility supported by actual production or conclusive formation test', but they allow 'immediately adjoining portions which can be reasonably judged as economically productive', whereas this report allows 'in an area where many similar reservoirs have been conclusively tested, log evaluation alone may be considered sufficient evidence of productivity.'.

e) The SEC allow 'improved recovery techniques in 'proved reserves' following successful testing by a pilot project or the operations of an installed program', whereas this report also allows (in the expectation curve) 'analogy with the same process being used elsewhere under similar conditions or occasionally as a result of laboratory/simulation tests'.

f) This report add 'without major expenditure' as a qualified to the developed reserves category such that 'a rig entry, for any job other than a repair, will normally be considered as major expenditures'. The use of 'existing facilities' is also extended by this report to include 'those which are firmly planned (i.e. budget approved)'.

Point a) has been endorsed by external auditors and accepted by the SEC. The amendments of points b) and c) are expected to roughly cancel each other out. The amendments of points b), c) and f) are considered justified because they give guidelines which are easier to apply and more relevant since they are tied to long-term planning and investment decision. The amendments to points d) and e) allows the use of analogy, which is more cost-effective and may be equally valid in areas where reservoir characteristics are well-defined.

Finally, a recent paper in the Journal of Petroleum Technology is worth noting since it presents an extensive classification system. It's five-dimensional system is based on: ownership, energy source, degree of proof (proved, probable, possible, prospective), development status and producing status. Ownership and energy source are considered as identifiers of hierarchy and hydrocarbon type in the system proposed by this report. The degree of proof and development status is handled by the calculation method and the classification system proposed by this report. Producing status has been rejected in this report.

DEFINITIONS ADOPTED FOR CLASSIFICATION, ESTIMATION AND IDENTIFICATION

Petroleum resource: Liquid or gaseous mixture of predominantly hydrocarbon compounds occurring naturally in underground reservoirs. Non-hydrocarbons such as nitrogen and carbon dioxide may be included without comment, providing they each constitute not more than 1% by volume of the initially place volume. Greater proportions may be included, but should be explicitly mentioned.

Cumulative production: Component of the petroleum resource which has already been recovered at surface, from the reservoir.

Economically recoverable resource: Reserves plus production.

Reserves: Component of the petroleum resource whose expectation volume can be sown to generate an acceptable real term earning power upon development and production, based on current operating regulations, current projections of future prices and cost, and assuming production and/or development commences immediately.

Producibility should normally be demonstrated by production test or conclusive formation test. However, in an area where many similar reservoirs have been conclusively tested, log evaluation alone may be considered sufficient evidence of producibility.

The application of fluid injection or other improved recovery techniques can only be included if the process has demonstrated its ability to economically generate additional recovery. Such a demonstration is normally achieved through a pilot test, by analogy with the same process being used elsewhere under similar conditions or occasionally as a result of laboratory/simulation tests.

Developed reserves: Component of reserves which is believed to only be recoverable after major expenditure.

Undeveloped reserves: Component of reserves which is believed to only be recoverable after major expenditure.

Technically recoverable resource: Potential reserves plus economically recoverable resource.

Potential Reserves by unproved techniques: Component of potential reserves which is believed to be recoverable through processes which have not yet been demonstrated to be technically and/or economically feasible.

Hydrocarbons in place: Component of the petroleum resource which is believed to occur initially in the reservoir.

Productive field: a collection of petroleum-bearing reservoirs within a geologically defined boundary (both areally and with depth), at least one of which has been on continuous, controlled production or where development activity is approved.

Prospective field: A collection of petroleum-bearing reservoirs within a geologically defined boundary (both areally and with depth), at least one of which has been penetrated by the drilling bit and sown to contain petroleum, but from which thee has not been any continuous, controlled production and where development activity is not approved.

Prospect: A potentially petroleum-bearing geological feature within which no producible petroleum-bearing reservoirs have been penetrated by the drilling bit. This may include deep prospects in prospective or productive fields where such prospects are considered to be below the field boundary.

Lead A potentially petroleum-bearing area within which no producible petroleum-bearing reservoirs have been penetrated by the drilling bit.

Expectation volume: The weighted average or mean of an expectation curve for petroleum resource volumes, occasionally approximately by the sum of the proved, probable and possible volumes divided by three.

Proved volume: The petroleum resource volume with a high probability of being exceeded. Normally the weighted average of the middle third of the expectation curve, often approximately by the 85 percentile value.

Probable volume: The petroleum resource volume with a fair probability of being exceeded. Normally the weighted average of the least probable third of the expectation curve, often approximated by the 50 percentile value.

Possible volume: The petroleum resource volume with a low probability of being exceeded. Normally the weighted average of the least probable third of the expectation curve, often approximated by the 15 percentile value.

Chance factor: The likelihood of a petroleum-bearing reservoir being present, based on worldwide experience. Used to convert potential initially in place resource volumes, estimated for reservoirs which have not yet been show to contain petroleum, into likely volumes in order to obtain a realistic estimate of future additions to reserves from such resources.

Risk factor: The likelihood of particular process being technically applicable in a given reservoir, based on worldwide experience. Used to convert potential recovery volumes, estimated for known petroleum-bearing reservoirs, into likely volumes in order to obtain a realistic estimate of future additions to reserves from such resources.

Discounted resources: One which has been subjected to the application of a chance factor or a risk factor.

(Annual) depletion rate: Production during the year divided by the reserves expectation at the beginning of the year as inferred from the end year reserves minus production during the year.

Primary recovery: A production which utilizes the naturally available energy and displacement process in the reservoir in order to move petroleum through the reservoir to wellbores or other points of recovery.

Improved recovery: A production process which supplements the naturally available energy and/or improves the displacement processes in order to move more petroleum through the reservoir to the points of recovery.

Crude oil or oil: Component of the petroleum resource which occurs in the liquid phase in the reservoir and remains a liquid at atmospheric conditions, after production and surface separation.

Natural gas liquid (NGL): Component of the petroleum resource which occurs in the gaseous phase in the reservoir and remains a liquid at atmospheric conditions, after production, surface separation and possibly gas processing.

Natural gas or gas: Component of the petroleum resource which occurs in the gaseous phase or is in solution in crude oil in the reservoir, but becomes or remains a gas at atmospheric conditions, after production, surface separation and gas processing.

Condensate: Component of NGL which comes from surface separation. Generally pentanes and heavier hydrocarbons, depending on separation conditions.

Liquified petroleum gases (LPG) : Component of NGL which comes from gas processing. Generally butanes and propanes, depending on separation conditions.

Solution gas or dissolved gas: Component of natural gas which occurs in solution in crude oil in the reservoir.

Free gas, gascap gas or dome gas: Component of natural gas which occurs in the gaseous phase in the reservoir.

Associated gas: Natural gas which exists in reservoirs containing crude oil.

Non-associated gas: Natural gas which exists in reservoirs containing negligible or no crude oil.

Wet gas: Natural gas containing significant amounts (generally more than 2% by volume) of hydrocarbons heavier than methane.

Dry gas: Natural gas containing insignificant amounts (generally less than 2% by volume) of hydrocarbons heavier than methane.

Committed gas: Natural gas which is contracted to sale or can be considered as such. this includes the gas used and gas losses incurred in order to supply contract volumes.

Uncommitted gas: Natural gas which is not contracted to sale or cannot be considered as such.