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Can We Be More Efficient in Oil and Gas Exploitation? A Review of the Shortcomings of Recovery Factor and the Need for an Open Worldwide Production Database.

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Abstract

This paper critically reviews the concept of recovery factor (RF) of oil and gas fields. Although this simple parameter is used throughout the oil and gas industry, it is subject to misunderstanding and misuse. Besides changing continually through the producing life of a field, the estimate of RF is affected by geological uncertainty, inappropriate reserves reporting, technological shortcomings, commercial practices and political decisions. At present, the information necessary to fully evaluate RF is not unequivocally determined, audited or reported, which makes it impossible to produce consistent global field statistics. Based on the authors' experience, the paper outlines the shortcomings of RF and suggests how they may be overcome. To promote clarity and transparency in RF calculations, a template for an open worldwide production database is proposed.

Introduction

Accepted wisdom suggests that the higher an oil or gas fields' value of RF, the more efficient the hydrocarbons have been produced from the reservoir. Optimising the recovery from a hydrocarbon field should be the common goal of both Governments and Operators, although increasing production levels at the right economic and political moment may prove too tempting to some. Hence, the use of RF as a yardstick to measure the performance of a reservoir (or the management of that reservoir) has some serious shortcomings. In order to use RF appropriately, it is important to understand what it is, how it is calculated and the uncertainty inherent to the parameters from which it is derived.

The value of RF is defined as the ratio of the recoverable volume to the hydrocarbons originally in place (HOIP) over the course of a field's economic life. Yet this seemingly trivial calculation has inherent uncertainty and can vary due to many reasons.

Among the many factors that impact on the ultimate recovery from a field are: the geology of the reservoir; the properties of the reservoir fluids; the drive mechanism; the technology used to drill, complete and produce the field; the oil and gas prices. The RF of "tight" hydrocarbons reservoirs can be as low as 1%, but it can be as high as 80% for reservoirs of excellent porosity and permeability. In addition, for a given geology, enhanced oil recovery (EOR) methods can recover more oil from the same reservoir. It is common practice to differentiate between primary, secondary, and tertiary (or enhanced) oil recovery. With primary recovery, the natural potential of the reservoir drives the oil to the surface and this can be combined with well-bore artificial lift techniques, but only a small amount (~10%) of the HOIP can be recovered by this method. Injecting water or gas to displace oil is referred to as secondary recovery and this usually allows a recovery of 20-40%. The field characteristics that lead to high primary and secondary recovery are summarised in Table 1.

Tertiary recovery may lead to recovering ~60% or more of HOIP, using methods such as:

- Thermal recovery, by adding heat to the reservoir fluids to make them more mobile.

- Gas injection for miscible sweep of the oil, is achieved by injecting flue gases or CO_2, which dissolve in the oil, reducing its viscosity and increasing its mobility.
- Chemical injection, either using polymers to "thicken" the injected water to increase its viscosity and so improve water-flood efficiency, or using surfactants, to improve the mobility of the oil droplets by reducing the surface tension.

• Homogeneous at all scales
• Good connectivity
• Good (induced) fluid mobility
• Gravity stable at reasonable rates
• Appropriate natural drive
• Non-fractured
  or homogeneous, densely fractured
• Clean, sweet oil
• Thick oil column, large areal extend
• Good, cheap accessibility
• Good monitoring (seismic, etc) ability
• Consolidated sands
• Low residual Hydrocarbon saturation

Table 1: Main features of high-recovery fields. (Schulte, 2005).

The RF values quoted above are suggested by the U.S. Department of Energy and reflect the USA experience. The numbers do change for different geographical areas, e.g. the average RF in the UK North Sea for a water-flood oil field is around 45% and may be up to 60% in some fields. However, care must be taken before applying average RF values to all fields as heavy oil, tight gas, HP/HT fractured and deepwater reservoirs present special challenges and, therefore, different levels of recovery should be expected.

The estimate of RF has an element of time dependency. When considering hydrocarbon reserves, it is important to distinguish between the reserves of fields that have already been abandoned and the reserves of fields that are either about to come on stream or in the early years of production. The evolution of uncertainty for reserves estimation for a generic field is shown in figure 1, where the uncertainty reduces as more information is gathered from the field, from the exploration and appraisal stage to abandonment.

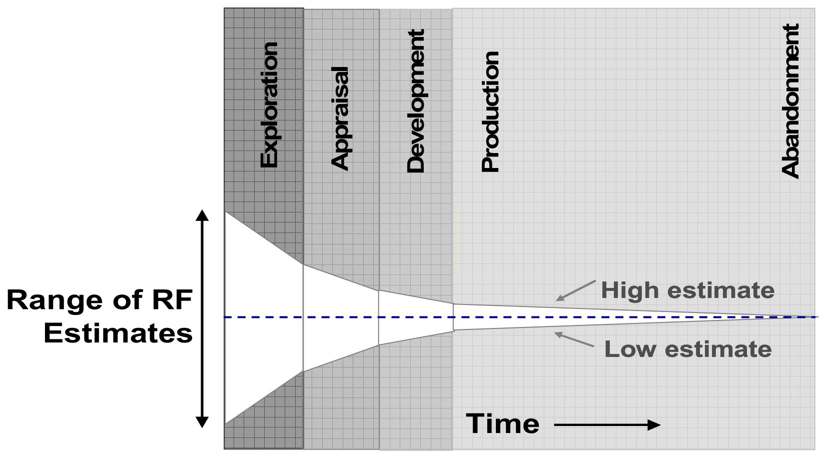

Figure 1: Uncertainty of reserves estimation decreases as field life progresses

Hence, reserves do change over an asset's life as does HOIP as more reservoir data is gathered during development drilling and production history is matched. Some analysts claim that RF does not change over time, but the authors disagree with this statement.

Not only do the reserves change over the life of a field, the method used to compute reserves also changes. Figure 2 illustrates that different reserves determination methods (use of results from analogue fields, volumetric calculations, decline curve analysis, material balance and numerical simulation) are used at different stages of a field's life.

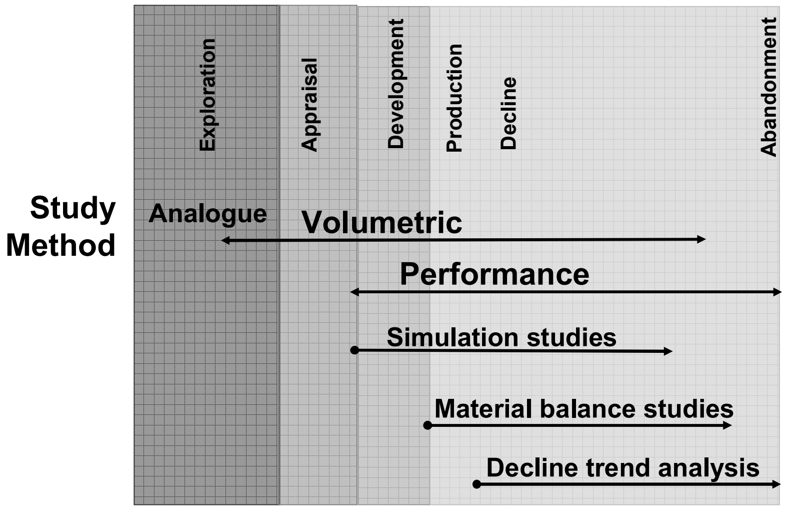

Figure 2: Reserves determination methods change through field life

As mentioned earlier, besides time dependency, there are many other factors affect the RF, which reflect geological risk, regulatory guidelines, technological shortcomings, commercial practices or political stances. Some of the more important factors are:

- Uncertainty in value of HOIP.
- Definition of reserves and reporting standards.
- Metering error(s) when measuring produced volumes.
- Application of new technology to enhance well productivity.
- Change in operatorship of the asset.
- Change in business model used by operator.
- Paucity of verified field and well data in the public domain.

The above factors, their effect on RF estimates and how their impact may be lessened are discussed in detail below.

Factors Affecting Estimation of RF

The following factors influence RF; some implicitly, some explicitly, but they can all have a major impact on its estimate.

Uncertainty in HOIP.

The recoverable volume will only be known when all the reserves from that field have all been produced, but the HOIP will probably never be known for certain. This is because the cumulative produced volume can be metered, but the HOIP must be estimated from seismic surveys, well logs, geological models and hydrocarbon samples. Thus, even after all reserves have been produced, the actual RF will have inherent uncertainty as the HOIP is estimated, not measured. Hence, the HOIP of a field can go up or down, depending on revisions of the original numbers and/or field extensions. In the case of field extensions, the extra reservoir volume may be of a better or worse quality than the original discovery, therefore the overall RF may be lower or higher than that originally predicted.

Definition of Reserves.

There is currently no unique way of defining and assessing reserves, although the Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC) have jointly published a guideline (SPE-WPC, 2007) that purports to do just that. Neither is there a global standard for financial reporting purposes. The reserves may be reported in different ways, more conservative or more likely, and the RF will reflect the choice of reserves reporting. Some of the reserves databases that are available in the public domain will be discussed later in the paper.

Reserves are usually estimated according to a probabilistic approach, where a differentiation is made between proven, probable and possible reserves. In some parts of the world, companies only have to report proved reserves (referred to as 1P or P90). In other countries, the probable reserves (2P or P50) are issued. Finally, some classification systems are extended to include possible reserves (3P or P10). As the value of an oil and gas company is a direct function of its forecast reserves base, the same company may show completely different results depending on whether 1P, 2P or 3P numbers are used.

Production profiles that are based on 2P reserves are more optimistic than the 1P, yet more conservative than the 3P. In asset sales, the 3P or upside reserves of a field development may be taken into consideration. Different available databases report different types of reserves. This will be covered later in the paper.

Figure 3 shows how reserve growth occurs when reserves are reported as proven, but does not statistically occur when the reserves are reported as probable (2P). The figure highlights the possible confusion that may arise in quantifying reserves when using 1P numbers only.

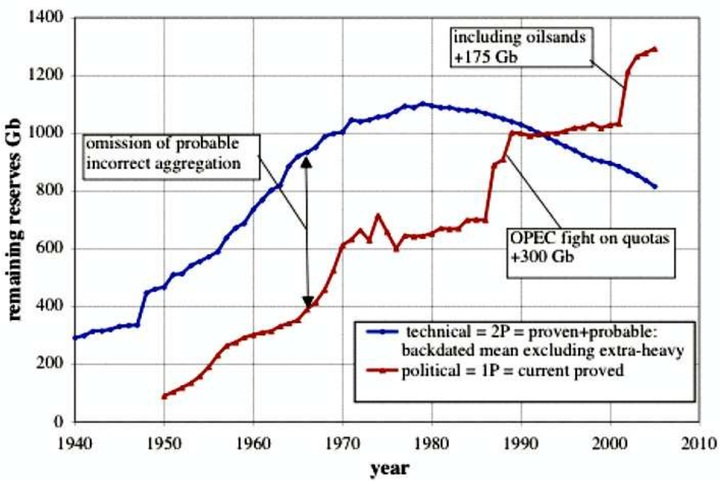

Figure 3: World remaining conventional oil & gas reserves from “political” & “technical” sources (Laherrère, 2006)

When aggregating the reserves of a company, two common practices exist. The first is based on the arithmetic summation of deterministic estimates, whilst the second performs a probabilistic (or statistical) aggregation of probabilistic distributions. The difference between these two methods is illustrated in Figure 4, which is taken from the guideline (SPE-WPC, 2007).

In order to correctly add together the ranges of reserves from a number of fields, the second method of probabilistic aggregation must be used. Reserves distributions tend to be skewed log-normal, as they are based on permeability variations. The only point where the deterministic and probabilistic results coincide is at the mean or average value of the aggregated distribution. Thus, when working out the overall reserves distribution curve of several fields, the P50 of the total curve does not correspond to the sum of the individual P50s. The log normal distribution ensures that the computed mean is always higher than the P50 value. The larger the skew of the resultant reserves distribution, the bigger the difference between the computed mean and the P50 value. Traditionally, companies have quoted reserves ranges as 1P-2P-3P (P90-P50-P10) values. However, the authors have seen many instances where the aggregated reserves of a number of fields have been incorrectly determined. It is the authors' opinion that reporting a field or aggregated fields' mean reserves over time are the best estimate for ultimate recovery. From the discussions above it follows that a unique definition of reserves is needed prior to defining the RF.

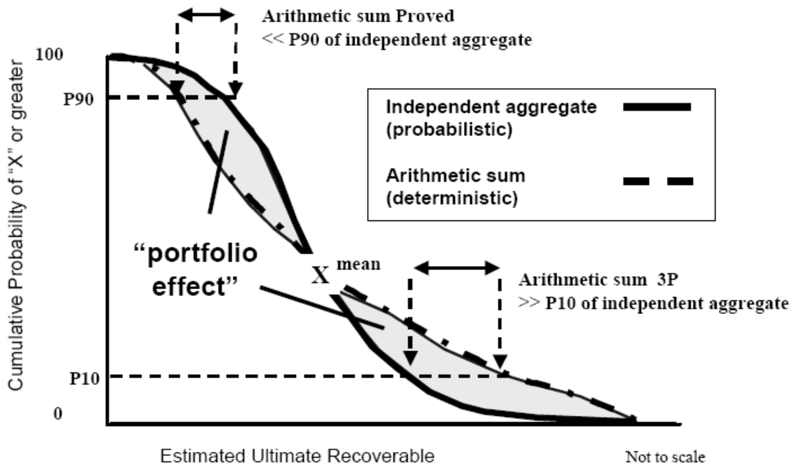

Figure 4: Deterministic versus Probabilistic Aggregation of Reserves (SPE-WPC, 2007).

Metering Error(s).

When using reservoir modelling techniques to forecast oil and gas production, from which the ultimate field recovery can be predicted, the volumes and flow rates of fluids produced from a reservoir are used to tune the models. However, the metering of the produced fluids is not error free; the measurements may be taken with different levels of accuracy, depending on whether they are required for fiscal, allocation or reservoir management purposes. In the latter case, an accuracy of ±10% for the measurement of the produced hydrocarbons is generally considered to be acceptable. The metering uncertainty is particularly important for small discoveries or marginal fields, where the effect of wrongly predicting the ultimate reserves and RF can severely impact the overall field economics. Since the results from production measurements are implemented in the reservoir modelling or production optimisation processes, it is clear that the accuracy of such measurements will affect the prediction of ultimate recovery from a reservoir. More accurate measurements imply that this uncertainty can be reduced. It is also clear that different levels of uncertainty may be acceptable, depending on overall field reserves, oil price, production lifetime, etc.

Application of New Technology.

It is often suggested that new technology can enhance the produced volumes and therefore accelerate and, in many cases, increase the recovery from a field. In the last decade, some fundamental technological advances have been made in remote detection (higher definition and

4D seismic, controlled source electro magnetic surveys (CSEM)), drilling and completions (e.g. geo-steering, multilateral producers, under-balanced drilling, smart wells), well logging, real time reservoir monitoring (including multiphase flow metering and fibre optics), sub-sea and down-hole technology (e.g. water shut-offs, water separation), multiphase transport (including multiphase pumps and wet gas compressors) and flow assurance.

An example of where new technology has enhanced recoverable reserves is represented by tight gas reservoirs. These formations, which are classified as having permeability less than 0.1 md, may contain at least 1,300 $x10^9$ m^3 of gas worldwide (BGR, 1999). Many tight gas reservoirs were discovered years ago, but their potential has still to be fully realised due to their low productivity when developed with "conventional" completions and reservoir management techniques. However, this situation is already changing, as new technology improvements and the recent gas price hikes have seen a rapid development of tight gas sands worldwide, and particularly in the US. Table 2 summarises the quantitative impact of new technologies on tight gas resources (Perry *et al.*, 1998). The cumulative impact of new technology results in an average tight gas producer with an increased recovery of 25% and a cost reduction of 17%.

New Technology	Impact	Well Cost Impact
Geo-steering for zone selection	Keep well in higher quality pay zones	+ 5 %
Under Balanced Drilling (UBD)	Less fluid loss, minimise formation damage	+ 5 %
Drill multiple wells from a single location	Smaller footprint, quicker rig up/down	- 5 %
All waste disposed of on-site	Cuttings, drill fluids, produced water re-injected	- 5 %
Better fracture materials management	Bulk purchasing & handling, cheaper treatment	- 25 %
High angle drilling	Maximises reservoir interval penetrated	+ 5 %
Coiled Tubing drilling,	CT also be used as production tubing	- 10 %
Improved hydraulic fracture conductivity	More complete clean-up	+ 40 %
Monthly operating costs		- 20%

Table 2: Impact of new technology on tight gas recovery (after Perry et al, 1998)

With conventional technology, the RF for tight gas reservoirs is very low, up to 10%, which makes the majority of them uneconomic. However, new technology can increase tight gas RF to between 30 and 50% (Friedel, 2004). Combining several new technologies together has proved particularly successful in unlocking extra reserves from tight gas reservoirs such. One example of "combo-technology" is to geo-steer horizontal wellbores into better quality reservoir units, while avoiding depleted zones or aquifers, and subsequently completing them with multiple fracturing techniques (Bencic, 2005). The combined benefits are illustrated in Figure 5, which shows an increase in recovery of an additional 1000 million cubic metres of gas (at normal conditions) from a tight Permian sandstone.

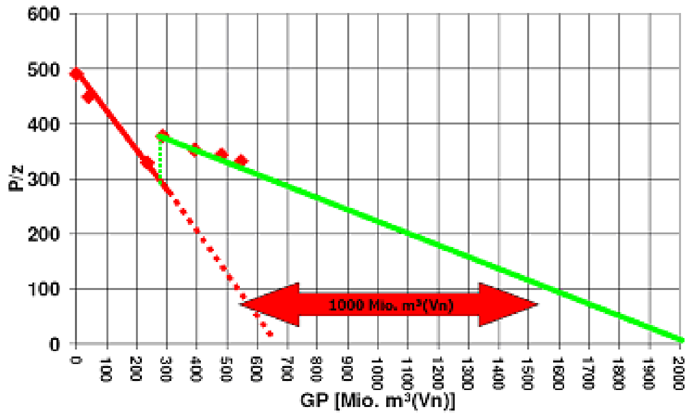

Figure 5. Unlocking gas well reserves by using combined drilling and fracturing techniques. (Bencic, 2005) [GP=Gas Produced; P/z=Reservoir pressure/gas compressibility factor]

However, while it is true to say that advances in key technologies may allow more recovery from a field, it is also true that novel technology may sometimes only accelerate the production of oil and gas volumes that would be equally produced using older techniques.

There also seems to be a correlation between RF values and oil and gas prices, and the higher the price, the more likely it is that new techniques are implemented in the field. There tends to be a lag time between when the oil and gas prices rise and when more expensive field development methods are adopted. An example of how the RF and the oil and gas prices are related is given by Canada's tar sands. Canada was not a significant player in the oil reserves charts until the oil prices jumped to over 50 $/barrel. At that point, the investors felt more confident in trying new exploration and production techniques to increase the recovery factor of tar sands and, since then, the World Oil Statistics position Canada in second place after Saudi Arabia for reserves.

Such dependencies of the RF could be easily proved (or not) if the appropriate data were made available by government agencies, as will be discussed later.

Change of Asset Ownership.

In order to quickly and efficiently implement field development opportunities, it is important to guarantee that the asset is always in good hands. Asset sales imply that a new study is carried out to evaluate the asset value, resulting in new investment and additional production. This is illustrated by an example in Figure 6, which shows the production profile for the Forties field in the UK. The observed increase in production resulted from the transfer of the asset from the previous operator to a new one, from BP to Apache in this case. Prior to its sale in 2003, the Forties field was stated to have HOIP of 4.2 billion barrels, but this was increased, after re-processing of 3D seismic and an aggressive infill drilling programme, to 5 billion barrels. The subsequent RF fell from the 2003 figure of 62% to 53%. Although the Forties field is a success case for change of asset ownership, such mature asset transfers can be financially complex due to decommissioning costs and liabilities (PILOT, 2005).

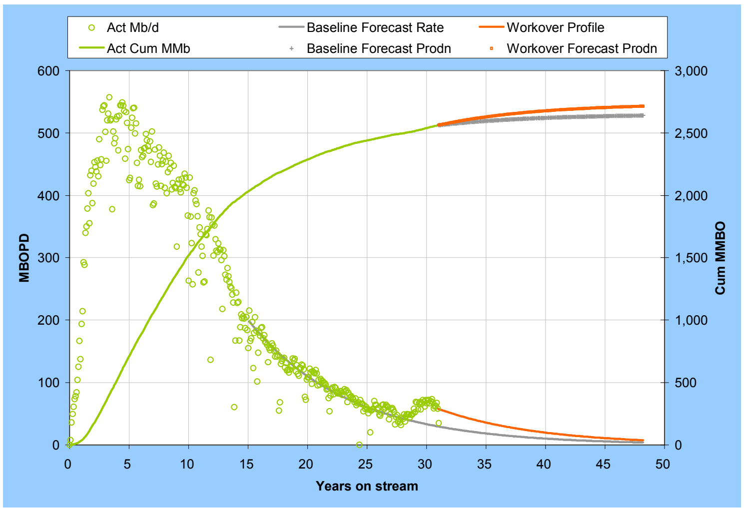

Figure 6: Forties field production, showing improvement (actual and forecast) over baseline by infill drilling programme by new operator (UK dti's PPRS online database, 2006).

Change of Business Model.

Another way to ensure the recovery from a field is maximised is to apply new business models and enhance cross-industry partnerships (PILOT, 2005). New start-up companies have appeared on the scene that invest in development projects and take technical control of them. They form partnerships with field owners to help increase production and earn a share of the incremental revenue. A typical cash flow for such business models is shown schematically in Figure 7.

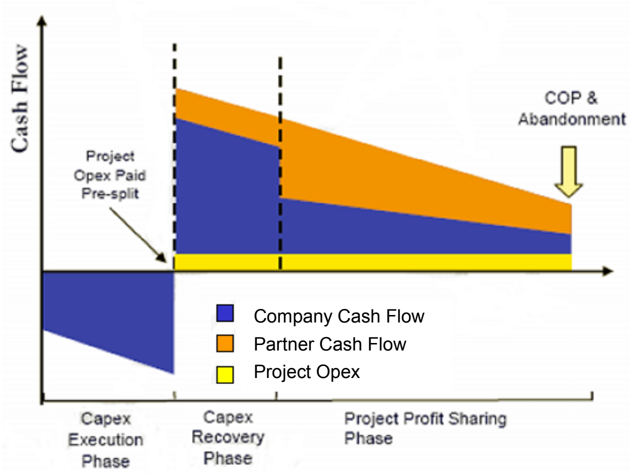

Figure 7: Cash flow of production sharing business model. (EDP 2005)

Paucity of Accessible Production Databases

In order to investigate the values of the RF of hydrocarbon fields worldwide, it is necessary to review historical production data and forecast reserves from available databases. While some countries and states have their own collection of production data by field (or even better, by well), no "official" database exists for all producing fields and/or wells worldwide. In fact, many countries treat their figures as confidential and do not disclose them.
Some of the resources that are available in the public domain include:

- BP Statistical Review of World Energy, summarise the production and consumption figures of hydrocarbon resources by country each year.
- Oil & Gas Journal (OGJ), provides production data down to an oil field level for each country in the world. This annual survey gives each oil field's rate in barrels per day, the oil's API gravity and the depth of the reservoir.
- Official online production databases, maintained and provided by some government and federal agencies. Some examples of these excellent, but limited resources are:
  - Well and field databases of some of the oil and gas producing states in the USA (California, Wyoming, etc.) are exemplary, giving almost everything analysts need to compute RF with some confidence.
  - Petroleum Production Reporting System (PPRS) of the UK's Department of Trade and Industry (dti), which gives online monthly data for each oil and gas field in the UKCS only three months in arrears. [*PPRS did provide detailed monthly production data on a well-by-well basis, but unfortunately this excellent service was discontinued in 1999 - a serious mistake in the authors' view*].
- Commercial Production & Reserves Databases, which attempt to provide a worldwide dataset, but they can only publish field data for the countries that disclose them. Two of the major providers of this data service are:
  - IHS, whose global database provides both reserves and HOIP figures, allowing RF to be estimated (although its accuracy will depend on the accuracy of the input data, which is provided by the host governments and operating companies). IHS has a tendency to be more exploration focused in its reporting.
  - Wood Mackenzie, whose global database only provides reserves and is less extensive than that of IHS, but covers some regions in greater depth. Wood Mackenzie has a tendency to be more production focused in its reporting.

Because of these inconsistencies in the way production and reserves data are released and published, it is not unusual to discover different databases with different production and reserves figures for the same field.
After discussing the various factors that impact on RF estimates, let us now see how their variability around the world makes it difficult to generate useful RF statistics without the availability of detailed and consistent field data from government agencies.

RF Statistics and their Limitations

A note of caution is warranted for those who analyse and use production and reserves data in the public domain. Because of the inconsistencies in the way production and reserves data are released and published, it is very difficult to generate valid and consistent RF statistics across the world. There is also missing information from published databases, which is not being released by all countries and/or field owners worldwide.
Nevertheless, several researchers have studied the published global data in an attempt to determine the range and average value of RF. Schulte (2005) reports a global average RF value of 34%; the results of his analysis are shown in Figure 8.

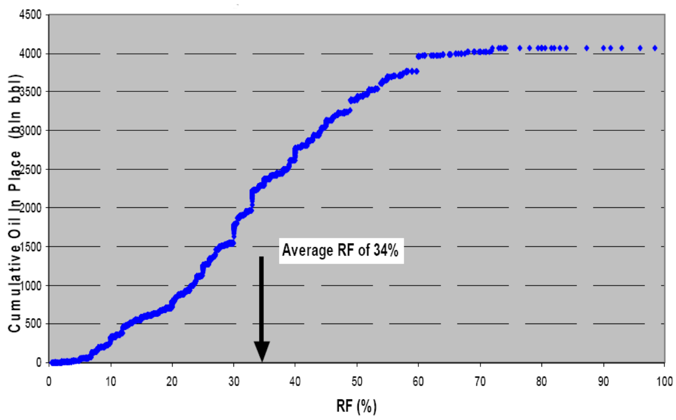

Figure 8: Global cumulative oil in place ordered for RF (data from IHS, no year specified). Schulte (2005).

Laherrère (2006) reports a slightly lower global average value of RF of 27%, as shown in Figure 9. It is unfortunate that this analysis does not provide the average field RF for 2001 and 2006 using the same fields, which would have been a better indicator of whether technology had improved RF over time.

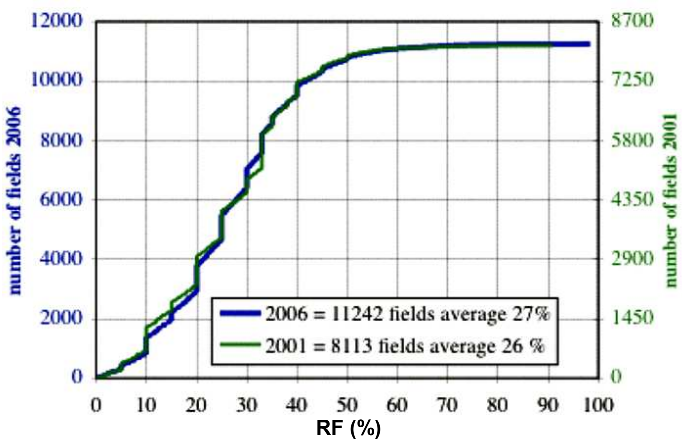

Figure 9: Cumulative number of oil fields worldwide (less US onshore) ordered by their RF (data reported in IHS database for 2001 and 2006) (Laherrère, 2006).

Figures 8 and 9 indicate an average oil RF of around 30%, but it must be noted that such plots do not make any differentiation by oil quality (heavy vs. light), reservoir depth, location, water depth (if offshore), geology, drive mechanism, etc. Also, the information displayed does not touch on the technology used (if any) to improve the recovery.

Another word of caution about statistics of the type shown in Figures 8 and 9: the stated RF could actually be higher if the oil originally in place has been overestimated and vice versa. In other words, it is impossible to separate the concept of recovery from that of resources originally in place, yet the latter are rarely published by government agencies.

Template for an Open Access Worldwide Production Database

As shown above, there is an inherent inaccuracy in estimating, measuring and reporting all the information necessary to determine the RF of a field. Also, depending on whether the RF is being estimated at the pre-development stage of a field or during its producing life, different data are needed to evaluate the RF. For pre-development, analogue fields help with the estimate of the new discovery's performance. In this case, the main criteria for screening analogue fields are the reservoir geology and fluid properties and the technology to be implemented. After field start-up, production data will become available and so allow the use of more sophisticated techniques such as decline curve analysis, material balance and/or numerical modelling to predict the field's recovery.

Accessibility to information on wells' performance, field behaviour, HOIP, geology, fluid properties and technology adopted is essential when estimating the RF of a field. This is true whether the field is a new discovery or on production. The data required to determine the RF through a cascade of input and output variables are summarised in Table 3.

	Item to be Reported	**Reported Variables for Item**	**Outputs Derived from Variables**
1a	Monthly well producer records	gas-oil-water volumes, days online, WHP, WHT, choke %	Producer Uptime, Well producing GOR-WOR-Water Cut, Well Decline Curve, Reserves per well, Field Reserves
1b	Monthly well injector records	gas, water volumes, days online, WHP, WHT	Injector Uptime, Injectivity model, Producer:Injector Ratio
1c	Well Technology	Artificially lifted? Stimulated? Water shut-offs? Horizontal or vertical? Completion details	Aids selection of appropriate analogue fields
3a	Monthly Field production records	gas-oil-water volumes	Field producing GOR-WOR-Water Cut, Field Decline Curve, Field Reserves
3b	Monthly Field injection records	gas, water volumes	Field Injectivity model (aquifer strength)
3c	Field Technology	Gas compression? Multiphase pumping? EOR?	Aids selection of appropriate analogue fields
4	Bottom hole Surveys	average reservoir pressure & temperature history (date and depth datum)	Material balance for HOIP
5	Top & Base reservoir structure maps	depth contours, scale, well locations, fluid contacts, major faults	Gross rock volume, Field area, Hydrocarbon fill factor
6	Field Geological description	sandstone or carbonate, matrix porosity or naturally fractured, massive or thin-bedded	Aids selection of appropriate analogue fields
7	Field Petrophysical parameters	porosity, water saturation, gross thickness, net-to-gross	Hydrocarbon pore volume (at reservoir conditions) [Combining Items 5 & 7]
8	Field PVT properties (Oil)	API gravity, solution GOR, viscosity, bubble point, FVF	STOIIP (at surface conditions) [Combining Items 5, 7 & 8]
9	Field PVT properties (Gas)	Gas gravity, condensate gravity, CGR, viscosity, dew point, H2S-CO2-N2, FVF	GIIP (at reservoir conditions) [Combining Items 5, 7 & 9]
10	**Recovery Factor**	**Field Reserves (from 1a or 3a), HOIP (from 8 or 9), with date reference**	

Table 3: Template for what production data should be provided by government agencies.
[WHP=Well Head Pressure; WHT=Well Head Temperature; GOR=Gas-Oil Ratio; WOR=Water-Oil Ratio; EOR=Enhanced Oil Recovery; PVT=Pressure-Volume-Temperature; FVF=Formation Volume Factor; CGR=Condensate-Gas Ratio; STOIIP=Stock Tank Oil Initially In Place]

Table 3 shows that field production data, injection data and reserves alone (which are the only data published in the majority of the available databases) are insufficient to estimate the RF from an engineering standpoint. Many more data are required, without which the published RF estimates must be treated with caution.

Conclusions

- This paper has highlighted the uncertainty in RF determination for hydrocarbon fields. This uncertainty is often underestimated and is due to the uncertainty in reserves determination and HOIP estimate.
- The concepts of RF and reserves are directly linked, so it is necessary to refer to the same reserves definition prior to being able to compare the values of RF worldwide in a consistent manner.
- HOIP should be published by government agencies, in order to avoid ambiguities when producing worldwide statistics.
- The publication of reliable HOIP and reserves will allow more confident estimates of RF to be made, which will help with the evaluation of new prospects by comparing them with analogue fields.
- Because of the strong interdependence between RF, reserves and HOIP estimates, it remains impossible to state, on a general basis, that new technology will improve the ultimate recovery from a field. This generalisation is particularly difficult considering that the geology of a reservoir, the properties of the fluids therein and its drive mechanism all impact on the estimate of RF.
- The authors believe that the stated dependencies of the RF could be easily proved (or not) if appropriate data were made available from government agencies. The data should include geology, fluid properties, well-by-well information, HOIP and a description of the type of drive mechanism and technology adopted for each field in the world. Although this may sound ambitious, it is based on the recognition that RF estimates issued without such supporting information may be totally meaningless.

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