

UKERC Review of Evidence on Global Oil Depletion

Technical Report 2: Definition and interpretation of reserve estimates

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Erica Thompson¹
Steve Sorrell²
Jamie Speirs³

1. Department of Earth Science and Engineering, Imperial College
2. Sussex Energy Group, SPRU, University of Sussex
3. Imperial College Centre for Environmental Policy and Technology

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Preface

This report has been produced by the UK Energy Research Centre's Technology and Policy Assessment (TPA) function.

The TPA was set up to address key controversies in the energy field through comprehensive assessments of the current state of knowledge. It aims to provide authoritative reports that set high standards for rigour and transparency, while explaining results in a way that is useful to policymakers.

This report forms part of the TPA's assessment of evidence for **near-term physical constraints on global oil supply**. The subject of this assessment was chosen after consultation with energy sector stakeholders and upon the recommendation of the TPA Advisory Group, which is comprised of independent experts from government, academia and the private sector. The assessment addresses the following question:

What evidence is there to support the proposition that the global supply of 'conventional oil' will be constrained by physical depletion before 2030?

The results of the project are summarised in a *Main Report*, supported by the following *Technical Reports*:

1. Data sources and issues
2. Definition and interpretation of reserve estimates
3. Nature and importance of reserve growth
4. Decline rates and depletion rates
5. Methods for estimating ultimately recoverable resources
6. Methods for forecasting future oil supply
7. Comparison of global supply forecasts

The assessment was led by the Sussex Energy Group (SEG) at the University of Sussex, with contributions from the Centre for Energy Policy and Technology at Imperial College, the Energy and Resources Group at the University of California (Berkeley) and a number of independent consultants. The assessment was overseen by a panel of experts and is very wide ranging, reviewing more than 500 studies and reports from around the world.

Technical Report 2: Definition and interpretation of reserve estimates is authored by Erica Thompson. It clarifies the nature of oil reserve estimates, the methods by which they are produced, the manner in which uncertainty is estimated and expressed, and the difficulties of aggregation. It summarises and compares number of commonly used classification schemes and investigates why reserve estimates change over time. It highlights both the limitations of current estimates and the extent to which they may be misinterpreted. It concludes that current reporting practices are only poorly suited for the purpose of forecasting future global oil supply.

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Executive Summary

The major inconsistency between reserve definitions is the choice of either a deterministic or probabilistic methodology. Within the class of deterministic definitions, the terms 'proved', 'probable' and 'possible' are widely used, but the use of this language is not standardised. Various descriptive terms are used which have very subjective interpretations. Within the class of probabilistic definitions there is wide agreement that 90%, 50% and 10% probability levels are appropriate to specify when reporting reserve estimates. Where deterministic terms such as "proved" are specified in a way allowing retrospective evaluation of estimates, the actual use of the term may not match the corresponding probabilistic definition.

There is a large physical uncertainty in our estimate of the oil originally in place due to the impossibility of measuring physical and geological characteristics of the reservoir sufficiently accurately. Further uncertainty is introduced in estimating how much is both technically feasible and economically viable to extract, and again when aggregating results for individual fields to large areas. Probabilistic estimates are therefore the most appropriate, because the definitions themselves include an acknowledgement of uncertainty.

Probabilistic definitions do not lessen the intrinsic physical uncertainty in making an estimate but they can eliminate the possibility of deliberate or accidental bias. Because probabilistic definitions allow retrospective evaluation of the accuracy of reserve estimates, errors in estimation can be identified. This level of accountability is not achievable with deterministic definitions.

Deterministic estimates cannot be aggregated by simple addition, because the terminology used to describe them represents an underlying distribution of probability. Due to this, aggregation of 1P estimates causes an underestimation of total proved reserves and aggregation of 3P estimates causes an overestimation of total proved, probable and possible reserves. Aggregation of 2P estimates correctly interpreted as the median introduces quantitatively less error, which may be positive or negative depending on the underlying distribution. If the 2P estimates are (incorrectly) interpreted as the mean estimate, then there will be no bias upon aggregation.

Given that the aggregation of 2P estimates introduces less systematic error than the aggregation of 1P estimates, they should be preferred when assessing aggregate reserve data. However, the aggregation of the 1P estimates at least provides a good lower bound for total reserves, whereas the direction of the error in the 2P estimates is unknown until the probability distribution is found.

Various reserve definition schemes have been proposed to harmonise the terminology that is used across countries, companies and organisations. The most successful of these has been the SPE Petroleum Resources Management System. This is mainly deterministic in character but does include a suggested correspondence with probabilistic figures. It is now used by many agencies and has had considerable influence on accounting standards. However, it is by no means universal and since it allows for completely deterministic reserve declarations, consistency cannot be

checked. The choice of definition and inclusion of different oil categories significantly influence estimates.

Given the observations above, the current definitions must be concluded to be very unsuitable for the purpose of forecasting future global oil supply. To produce meaningful estimates of global oil reserves will require standardisation of reserve definitions and of their interpretations, which can only be done with probabilistic definitions. It is likely that current estimates of global 1P reserves are significantly understated while estimates of 3P reserves (when available) are significantly overstated. The best estimate of global future production would come from the use of 2P reserve data, but it is currently not possible to say whether this is likely to be an under- or overestimate. Further work should, however, be able to reduce uncertainty at least in those areas where field data is available to assess estimation success retrospectively.

1 Introduction

The world is becoming more and more dependent on oil as its main source of energy. As the IEA's World Energy Outlook (2008) says, "*oil is the world's vital source of energy and will remain so for many years to come, even under the most optimistic of assumptions about the pace of development and deployment of alternative technology*".

Given our dependence on a source of energy which is ultimately finite, it is natural to ask at what point we expect to see global oil supply being restricted by depletion of the resource. Although distinct from so-called "above-ground" factors such as economic and political expediency, conflict, terrorism and underinvestment in infrastructure, physical depletion is necessarily intertwined with such factors. But while such factors may influence the rate at which oil can be extracted, they will not be considered in any detail here except as influences on the ways in which physical reserves may be estimated. Instead, the focus of this report is the definition and estimation of oil reserves and the interpretation of oil reserve estimates. In particular, it considers whether current definitions (and interpretations of those definitions) are appropriate for the purpose of determining the quantity of oil that is both technically possible and economically feasible to extract within a given time frame.

Section 2 explains in detail what is meant by petroleum reserves, the geological basis of reserve definitions, and how reserves are estimated in practice, including how these depend upon technical and economic assumptions and are affected by various institutional, political and market influences. Reporting standards and deterministic and probabilistic reserve estimates are introduced, to be discussed in detail later.

It is important not only to estimate the size of reserves, but also to estimate the corresponding uncertainty in the final estimates. As described in Section 3, the usual way of doing this is to produce low, "best" and high estimates, although the exact definitions of these may differ. Statistics can then be applied to the reserve estimates to evaluate them, or to produce estimates of aggregate reserves. A number of common errors and inconsistencies are analysed and their likely effect on aggregate reserve estimates assessed.

Many different reserve classification schemes are used world-wide and a selection of these are described in Section 4 along with their respective advantages and limitations. These are the definitions of the US accounting standard, the Society of Petroleum Engineers' (SPE) industry standard classification system, a classification by the United Nations and the definitions used by the UK Government.

Over time, reserve estimates change for a variety of reasons which are associated with discovery, production, definitions, measurement and other influences. The significance of each of these factors is discussed in Section 5.

Finally, Section 6 summarises the main findings and concludes that current reserve definitions are not adequate for the purpose of global reserve estimation. Despite some movement towards greater standardisation and better use of statistics, there is still both considerable uncertainty in the estimates of global oil reserves and frequent

misinterpretation of the relevant data. This in turn contributes to a corresponding uncertainty in forecasts of future global oil supply

2 Defining and estimating reserves

The first definition to consider is what we mean by a petroleum reserve. Figure 1 shows the influential classification introduced by McKelvey (1972), who distinguishes between reserves and resources:

- *Reserves* are those quantities of oil in known fields which are considered to be both technically possible and economically feasible to extract under defined conditions.
- *Resources* are the total quantities which are estimated to exist, including both those in known fields which are not considered economically feasible to extract and those in undiscovered fields.

While most commentators interpret the term reserves in a broadly similar way, there is considerable ambiguity over the use of the term resources. In addition to the McKelvey definition, this term may be used to refer to: the reserves in known fields; the technically and economically recoverable resources in a region, including those in undiscovered fields; and the total oil-originally-in-place (OOIP) in a region, whether discovered or not and whether recoverable or not.

The ‘McKelvey Box’ (Figure 2.1) classifies petroleum resources along two dimensions, namely the level of geological knowledge and the estimated economic viability of recovery. In the earliest versions, this simply distinguished between *discovered* and *undiscovered* resources. Later classifications of petroleum deposits follow this division by economic and geological factors, then further divide reserves into subcategories of *proved*, *probable* and *possible* reserves. The total petroleum resource estimated to be recoverable from a given area (which differs from the total ‘oil in place’, since not all may be recoverable) is the *ultimately recoverable resource* (URR) for that area. At any point in time, the URR is equivalent to the sum of cumulative production, remaining reserves, and the estimated recoverable resources from undiscovered deposits - normally termed ‘yet-to-find’ (YTF). We will consider this terminology in more detail later.

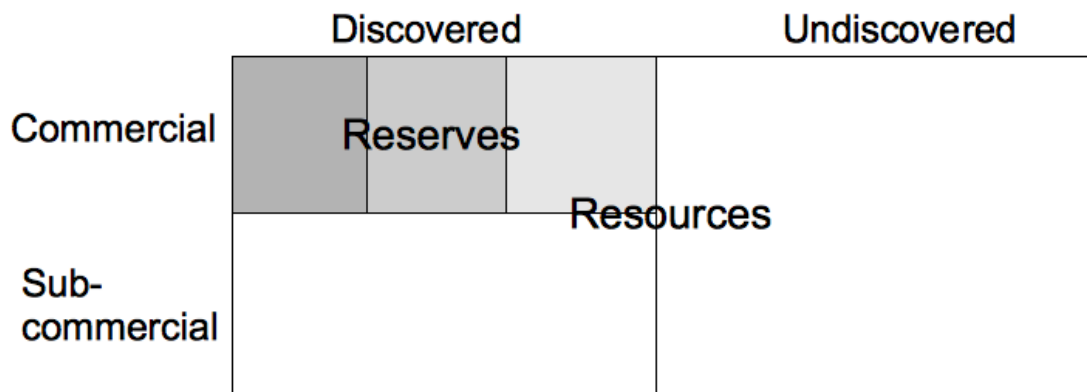


Figure 2.1: The “McKelvey Box”, from which most current petroleum resource classifications are derived. The geological axis is divided simply into discovered and undiscovered deposits, and the economic axis into commercial and sub-commercial projects. Later, the category of reserves (discovered, commercially extractable deposits) is divided into sub-categories.

2.1 What is being estimated?

Accumulations of oil or gas are termed *pools* or *reservoirs* and a geologically related group of reservoirs is termed an oil *field* (see Box 2.1). Individual fields may produce both oil and gas, although usually one or the other predominates.

Estimating the volume of oil contained in a reservoir or field is not as simple as estimating the volume of a bath full of oil. First, the reservoir may be a very complicated shape due to its geological origins. Second, the oil is not present as a pool of liquid but is trapped within tiny pore spaces in the rock matrix. This matrix is usually heterogeneous (varies from place to place within a reservoir), so even if the volumetric extent of the reservoir is known, the fraction which is oil may vary from one area to another. Third, even the most sophisticated equipment cannot accurately detect the presence of oil without drilling a physical borehole down to the reservoir, so the information that is used to predict the extent of the oil field comes mainly from exploratory and development drilling (Barss, 1978; Speers and Dromgoole, 1992), after which it is dependent on the judgement of field geologists to “join the dots” and infer the conditions between the known sites (see Figure 2.2)

Box 2.1 Geological levels of aggregation in petroleum resource assessment

- *Petroleum Well*: A well may be drilled to find, delineate and produce petroleum, with some wells being drilled to inject fluids to enhance the productivity of other wells. The URR of a producing well is typically calculated by extrapolation of its past production performance, using standard formulae for “decline curves” (Abd-El Fattah, 1996; Huffman and Thompson, 1994)
- *Petroleum Reservoir/Pool*: A reservoir is a subsurface accumulation of oil and/or gas whether discovered or not, which is physically separated from other reservoirs and which has a single natural pressure system. Pool is an older term for reservoir and accumulation is an alternative term.
- *Petroleum Field*: A field is an area consisting of a single reservoir or multiple reservoirs of oil and gas, all related to a single geological structure and/or stratigraphic feature. Individual reservoirs in a single field may be separated vertically by impervious strata or laterally by local geological barriers. When projected to the surface, the reservoirs within the field can form an approximately contiguous area that may be circumscribed. However, other sources define a field simply as a contiguous geographic area within which wells produce oil or gas. In either case, the boundary of a field may shift over time and two or more individual fields may merge into one larger field (Drew, 1997). Oil fields are classified on the basis of their oil to gas ratio and may either be discovered (located by exploratory drilling), under development, producing or abandoned. The number of wells in a producing field may range from one to thousands.

Sources: DECC(2009); Klett (2004); Magoon and Sanchez (1995)

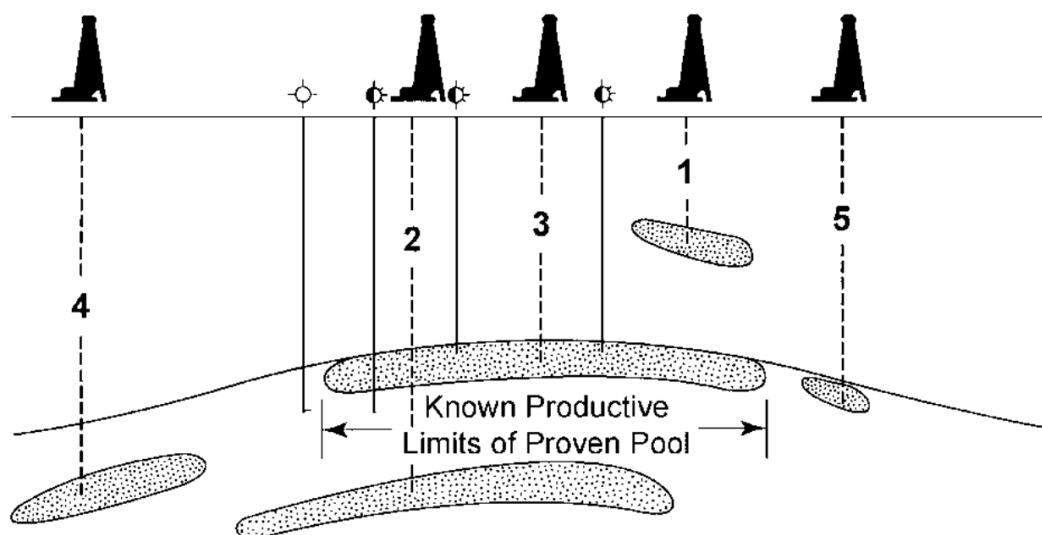


Figure 2.2: Illustration of the difficulty of judging what represents a single field. Disconnected regions may be classified either within the same field, or as new discoveries, depending on the definitions used and the order of drilling. Source: Attanasi and Coburn (2004).

Thus, starting with the largest quantity, we may choose to estimate the *oil initially (/originally) in place* (OIP or OOIP), which is the total amount of oil in the reservoir, field or region under consideration. We then estimate the *recovery factor*, usually given as a percentage, which is the fraction of oil that is considered to be recoverable under defined conditions. We must therefore also define whether this is under current economic and technological conditions, or conditional on some future projection of oil prices and technological development. The product of OOIP and the recovery factor gives the estimated *recoverable reserves*. There are then different subcategories of reserves depending on our level of confidence in the estimates of OOIP and recovery factor (Section 2.3). The more accurate the information we have about the field or region, the more accurately engineers can estimate reserves and predict future production. The total volume of oil that is estimated to be producible from the region, from when production begins to when it ends, is termed the *ultimately recoverable resource* (URR). As with reserves, estimates of URR are contingent upon assumptions about technical feasibility and commercial viability and can change over time as geological knowledge improves, recovery factors increase and oil prices change.

There are many other sources of information that geologists can use to improve their estimates of the reservoir volume and characteristics, but this illustrates the uncertainty of the estimation procedure and the extent to which it relies upon expert judgment. Once production has begun from an individual well, and the rate of production has begun to decline, the reserves or URR for that well may be estimated to a somewhat greater degree of confidence by extrapolating the rate of production using standard formula for ‘decline curves’ (Abd-El Fattah, 1996; Arps, 1945; Chaudhry, 2003; Gray, 1960; Huffman and Thompson, 1994; Sorrell and Speirs, 2009). While similar techniques can be applied at the field level, geological assessment may still be required to estimate reserves in adjacent areas that are not in contact with existing wells. Hence, in principle, all reserve estimates should be accompanied by a statement of how much confidence we have in the estimate, that is, the range of uncertainty or “error” that may be expected.

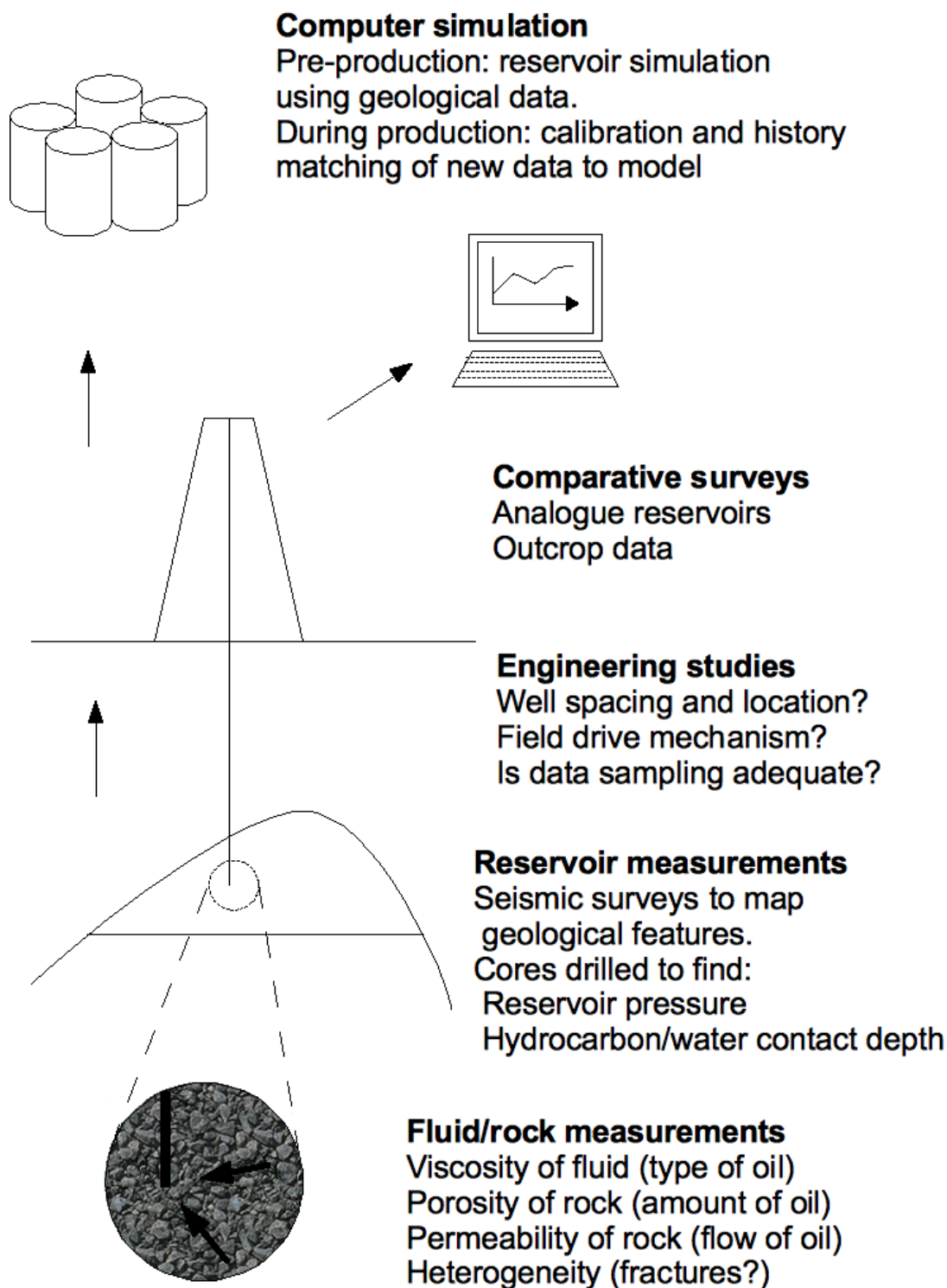


Figure 2.3: Geological assessment of petroleum reserves involves direct and indirect measurement of reservoir properties, as well as simulation using computational techniques both before and during production. (Not to scale). Sources: Speers and Dromgoole (1992), Barss (1978).

2.2 How can we estimate reserves?

As described above, the process of estimation requires various judgements, firstly on how much oil is in the ground, then on how much it is physically possible to extract,

then on how much it is economically viable to extract. Finally, there is a more political decision regarding how much of the estimated volume to declare publicly as reserves, which are governed by legal standards in most jurisdictions (of varying degrees of clarity) and may also be strategically important information for a company or country. The steps of assessment are described below, starting with those which are applicable to all petroleum extraction and moving to those which will differ depending whether an international oil company (IOC) with shareholders or a government-controlled national oil company (NOC) own the resource/reserve in question.

2.2.1 Geological assessment

Petroleum geologists are involved in exploration and discovery, and make the initial estimate of the amount of oil contained in a reservoir. First, the most promising regions are identified where it is believed that geologically it is possible or likely that oil may occur. Next, there is usually exploratory drilling to test for the presence of oil and measure properties of the reservoir rock (Barss, 1978). An estimate of the reservoir capacity is then made using the methods described in Figure 2.3.

Following successful exploratory drilling, a judgment needs to be made regarding the extent and size of the discovered reservoir or field (Figure 2.2). Instead of one large field, there may be several disconnected reservoirs in an area which, depending on the extraction strategy, may or may not be regarded as a single field (Speers and Dromgoole, 1992). In addition, this judgment may change over time, with previously distinct fields being merged into a single, large field, and larger fields being broken down into smaller ones (Drew, 1997). The choice does not influence the total discovered volume but it does affect the historical record of the size of discovered fields (Rose, 2007) which in turn may influence forecasts of future discoveries, since these frequently rely upon such records (Sorrell and Speirs, 2009).

2.2.2 Engineering assessment

Using the geological data provided, petroleum engineers then estimate the *recovery factor* - the fraction of oil in place that can be produced from the field with the technology available (IEA, 2008; Speers and Dromgoole, 1992). Most definitions of reserves take into account existing technology but do not allow for future developments which may enable more efficient extraction. However, recovery factors have improved in the past and may be expected to continue to improve in the future. For example, data from the America Petroleum Institute suggested that US recovery factors grew at an average rate of 0.2%/year between 1966 and 1979 (Davies and Weston, 2000). Some work has been done on predicting the increase in recovery factors on a semi-statistical basis (Klett, *et al.*, 2005), although improvements in technology are inherently uncertain and the achievable recovery will ultimately be subject to physical constraints. As recovery factors can only be calculated to the accuracy to which we know the total resource available in a field, there will always be some degree of uncertainty in the estimation of recoverable resources, even if technology is able to guarantee some minimum recovery factor.

A distinction is normally made between *primary recovery*, where oil is produced under its own pressure; *secondary recovery*, where either water or water alternating with gas (termed WAG injection) is used to maintain pressure and sweep oil from the reservoir, and *enhanced oil recovery* (EOR), where sophisticated techniques that alter

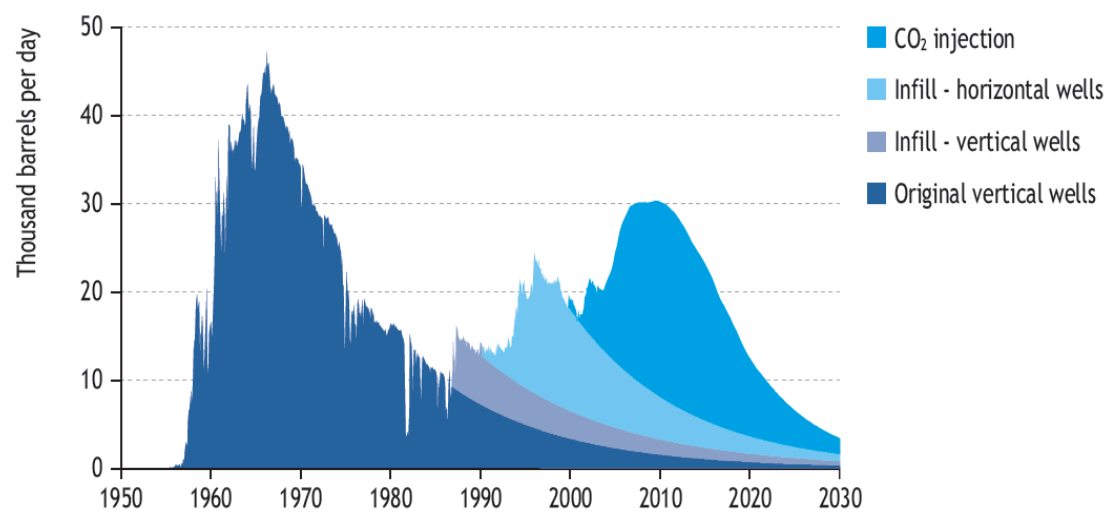
the original properties of the oil are used. EOR typically adds something to the reservoir, such as gas, solvents, chemicals, microbes, directional boreholes or heat, with the aim of raising pressure, preventing water flow, reducing oil viscosity, or accessing isolated sections of the reservoir. Box 2.2 summarises the most common types of EOR, although some of these, notably CO₂ injection, are classified as secondary recovery techniques by some commentators. A key point to understand is that techniques are very much targeted towards specific reservoir characteristics: not all techniques are appropriate or even implementable in all reservoirs. Most success has been achieved with thermal methods in highly permeable reservoirs containing heavy viscous oil, and miscible gas injection in less permeable reservoirs.

Box 2.2 Enhanced oil recovery techniques

There are three broad groups of EOR techniques:

- *Thermal* methods introduce heat, typically in the form of steam to reduce viscosity, partially ‘crack’ heavy oil and/or increase pressure. They are particularly suitable for heavy oil but their use has declined since the mid-1980s.
- *Gaseous* methods inject carbon dioxide, nitrogen or other gases at high pressure to reduce viscosity, achieve ‘miscibility’ (a homogeneous solution), displace water, sustain pressure and mobilise a larger proportion of the oil. CO₂ injection is the fastest growing form of EOR and is very effective for light oil. While many applications use natural sources of CO₂, future projects may be linked to carbon capture and storage (CCS) technologies.
- *Chemical* methods inject various compounds to reduce the ‘interfacial tension’ between oil and injected water. These are not widely used and tend to be complicated, unpredictable, costly and sensitive to reservoir characteristics.

The IEA (2008) use the example of the Weyburn field in Canada (see below) to illustrate what can be achieved with EOR – in this case with additional vertical and horizontal drilling followed by CO₂ injection. But it is not clear how widely this example can be reproduced.



Source: IEA (2008); NPC (2007); Sandrea and Sandrea (2007).

In general, recovery factors vary widely depending upon the type of rock in which the oil is found, its accessibility and the technology used. This is a critical area of uncertainty both in making single-field reserve estimates and in assessing global reserves and the future potential for reserve additions. The NPC (2007) suggest many potential advances in technology which could improve global average recovery factors from 35% to 50%. This would increase world reserves by about 1.2 trillion

barrels, or more than has been produced through to 2007. However, the IEA (2008) conclude that this will “*probably take much longer than two decades*” to achieve.

2.2.3 Economic assessment

The next consideration is whether extraction of a resource is economically viable for the extractor - will it result in a profit? Many reserve definitions include a clause stating that the reserve must fulfil certain *criteria* “*under existing economic and operating conditions*” (BP, 2008; IEA, 2008; SEC, 2008). However, this is a partly subjective judgement which depends on the current and anticipated future price of oil and the estimated capital and operating costs of extraction. Hence, for the purposes of declaration, the estimate will depend in part on the current market price for the relevant type of crude oil. In order for an operator to make decisions about future investment, however, they may prefer to consider alternative definitions in the light of their own projections of the future oil price (Jesse and van der Linde, 2008; Mitchell, 2004).

2.2.4 Institutional influences

Oil companies in different countries are subject to different rules and regulations regarding the estimation and declaration of reserves. The definitions of reserves may vary and even when a single definition is used, the interpretations of these definitions vary, with many relying on highly subjective assessment of “reasonable certainty” rather than numerical estimates of probability. Even when these terms are precisely specified, the interpretation is not always either correct or consistent. The reporting standards may also vary from one country to another. For example, in the US oil companies are required to publish only the “proved” reserve estimates in which the company has a high level of confidence (SEC, 2008), whereas in the UK “proved”, “probable” and “possible” estimates are all collated and made public by the government. Even within one country’s figures, there may be much variation between different operators regarding methods of estimation; for example, the UK government’s own website states that “*North Sea operators use a wide range of reserve and production estimation methods*”.

In the absence of a clear, consistent and widely used international standard, the definitions and approaches to reserve estimation vary widely from one country to another (where they exist at all). OPEC defines and declares “proved” reserves according to the SPE (2007) definition, but since no external or third-party auditors are admitted, there is no way of verifying their figures. While OPEC countries hold the bulk of the world’s oil reserves, their reserve estimates are widely contested (Deffeyes, 2005; Salameh, 2004). Other countries have their own legal rules and standards for estimation and declaration of reserves, and different methods for estimation are used by individual companies and petroleum operators (Arnott, 2004; Mitchell, 2004). This leads to considerable confusion about definitions and encourages the misinterpretation of reserve estimates.

2.2.5 Political and market influences

International oil companies (IOCs) should be largely unaffected by political considerations, but have a legal duty to their shareholders to maximise the return on investment. They are therefore subject to strong market incentives, since reserve estimates and the rate of reserve additions can affect their share price. The importance of reserve estimates is illustrated by the controversy in 2004 when Shell downgraded

20% of their “proved” reserves following reevaluation (Arnott, 2004). This led to a large fall in its share price, and eventually to the resignation of its chairman in June 2005.

National oil companies (NOCs), on the other hand, while they are less sensitive to market conditions and have no similar responsibility to shareholders, may have political motives for choosing particular reserves definitions, or for a particular interpretation of those definitions. For example, in the mid-late 1980's, reported proved reserves of OPEC countries increased by 80% - some 300 Gb (Bentley, *et al.*, 2007; Salameh, 2004). This was not due to the discovery of large new petroleum reserves, but a response to proposals by the OPEC Secretariat to link production quotas to reported reserves. The new figures cannot be conclusively said to be an overstatement of reserves, since there may have been both incentives to understate in the preceding years and improvements in recovery factors, but it does illustrate the scale of change that can occur due to changing incentives. Since the published reserve estimates of many OPEC countries have subsequently remained unchanged for periods of up to a decade, their validity has been further called into question (see Section 5.4).

Political and market influences are not usually mentioned in reserves definitions, as they are not a physical constraint on supply.

2.3 How is the estimate reported?

International oil companies will assess the geological, technological and economic conditions relevant to each of their undeveloped and producing fields and estimate the remaining reserves. These will be aggregated to the regional level and the estimate of “*proved reserves*” will be booked into the company's accounts. This is a single-number estimate and is often quoted without an indication of the level of confidence in the figure beyond the definitions supplied by the local financial reporting standard, which may require only “reasonable certainty” of the reserves' existence (SEC, 2008), and is not standardised between countries.

For publicly listed companies this is often the only freely available information, and it is also published by some NOCs, in particular the members of OPEC. However, due to the requirement of a high degree of certainty of achieving that figure, it will almost always be an underestimate of the volume of oil that will ultimately be recovered (Ross, 1998). Thus, for strategic planning many companies also make a “best estimate” of how much oil they believe it will, in time, be technically feasible and economically viable to recover (Mitchell, 2004). This is generally known as the “*proved and probable*” reserve estimate and is often further described as the amount of which production is “as likely to exceed as to fall short”. Further to that, some companies also consider a best-case scenario where all conditions prove favourable, and come up with a total estimate of “*proved, probable and possible*” reserves (SPE, 2007). National oil companies are not subject to the restrictions of accounting standards and tend to publish only proved reserves figures (Arnott, 2004). The terminology is summarised in Table 2.1, along with some other commonly used terms.

Table 2.1 Deterministic and probabilistic terminologies associated with oil reserves estimation.

Type of estimate	Deterministic terminology	Probabilistic terminology	Statistical description
Low	“Proved”: 1P	P90	10 th percentile
Best	“Proved and probable”: 2P	P50	Median
High	“Proved, probable and possible: 3P	P10	90 th percentile

Although some indication of the margin for error is provided by the use of these three figures (commonly abbreviated to 1P, 2P and 3P), they are all *deterministic* estimates, resulting from assigning one value to each input parameter and calculating a final estimate from this. The other approach to estimation is a *probabilistic* treatment, assigning definite probabilities to the input parameters and combining these within a Monte Carlo simulation or equivalent to find a range or *probability distribution* of possible outcomes.

3 Uncertainty in reserve estimates

3.1 Importance of estimating uncertainty

Since every measurement carries with it some degree of uncertainty, estimates of petroleum reserves need to be combined with estimates of the associated uncertainty (Jung, 1997; Rose, 2007). This uncertainty may be small in the case of well-characterised fields in extensively studied geological areas which already contain oil-producing formations; however, for fields in more speculative areas where little or no exploratory drilling has been carried out and there is no history of oil production, the uncertainty may be very large (Speers and Dromgoole, 1992). At the regional level, estimates are usually produced by summing field-level estimates, which must be done with care. There is even greater uncertainty regarding undiscovered resources, although since these do not contribute to declared reserves they will not be considered here.

The estimation and specification of the level of uncertainty in reserve estimates is important for several reasons:

- The amount of recoverable oil directly determines the economic viability of a project. Developing an uneconomic field could be disastrous for a small oil company, while choosing not to develop good fields would hinder a company's progress. The probability of making either type of error needs to be estimated in advance before development decisions are made.
- If an incorrect estimation of reserves is made, a company may be liable for damages incurred by shareholders on the basis of misinformation. A good prior estimate of uncertainty protects the company as it will then be possible to quantify the risk involved in publishing the so-called “best” estimate.
- Global oil reserves are economically crucial, but highly disputed, so the more information can be given about each estimate, the better governments and markets can respond to the availability of this resource.

But despite this, probabilistic estimates appear to be the exception rather than the rule.

3.2 Low/“best”/high estimates

As described in Section 2.3, reserves are usually quoted with “low”, “best”, and “high” estimates of recoverable petroleum quantities. In probabilistic terms, these are often identified with the “*P90*”, which has a 90% probability of being exceeded, “*P50*”, which has a 50% probability of being exceeded, and “*P10*”, which has only a 10% probability of being exceeded (SPE, 2007). These quantities can be graphically determined from the cumulative probability distribution, as shown in Figure 3.1.

Best estimates are easier to produce than low or high estimates, since the average properties are easier to estimate than outliers. But the interpretation of “best” estimates depends upon the particular definition that is used, which is by no means consistent.

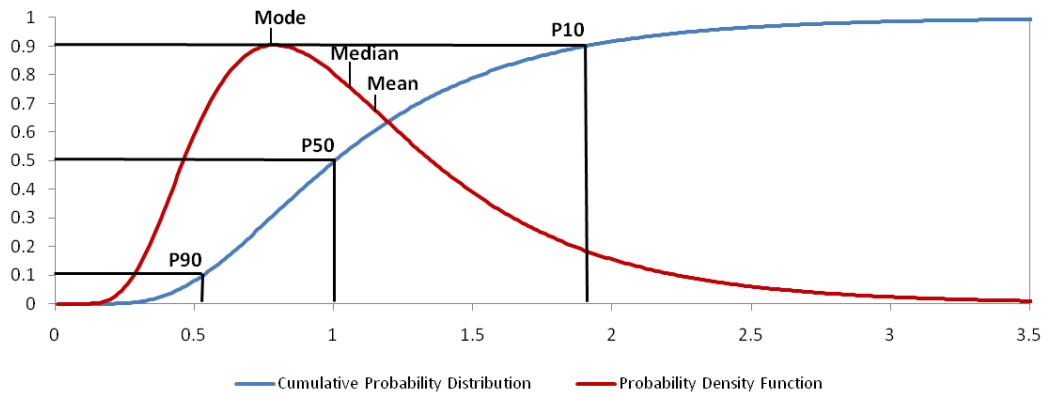


Figure 3.1: The probability density function (red line) represents a statistical distribution which in this example is skewed to the left. In the context of reserve estimates, there is no probability of there being a negative volume of oil, but there is a high probability of reserves being somewhere between 0.5 and 2 units, and a small probability of there being a much large amount. The P90, P50 (median) and P10 estimates all represent points on the cumulative distribution function (blue), which is the integral of the probability density function. The vertical scale refers solely to the cumulative distribution.

3.3 Issues in the treatment of uncertainty

3.3.1 Is the use of statistics even appropriate?

Objections to results obtained by statistical analysis of reserve estimations often centre on the observation that the initial stage of geological assessment contains very large and more-or-less unquantifiable uncertainties. For example, a geologist may estimate the porosity as “about 4 or 5%”, which is only one of a very large number of variables which must be considered, and immediately introduces an uncertainty of 10% in calculations done with this figure. The use of statistical techniques on such imprecise initial data (and the subsequent tendency to state results to 3 or 4 digits of precision) could therefore be criticised for lending an unjustified degree of credibility to results arrived at by these methods.

It is certainly sensible to be wary of mathematical results in the reserve estimation literature, as even the peer-reviewed articles often contain serious mathematical errors or inconsistencies. Common errors are highlighted with some examples in the following sections. There is also much confusion regarding the appropriateness of different methods for analysing the statistical data available. It should be noted, however, that widespread confusion does not invalidate the use of mathematics in general and there is probably still more to be gained from rigorous statistical analysis. Large uncertainties in themselves are not a problem mathematically, and we may to some extent use statistics to extract more useful data from behind the “noise” introduced by subjective estimation.

3.3.2 “Best” estimates

The UNFC EMR, a United Nations classification system for mineral resources, states that “*The best estimate shall be any of the mean (expected) value, the most probable (mode) value or the median (P50) value. It shall be stated which statistical measure has been used for the estimate.*” (UN, 2004) Other classification systems do not

specify the statistical definition of a 'best' estimate or implicitly assume it to be the median (P50). The distinction between the three kinds of 'best' estimate is important, as they can significantly affect the results of calculations, in particular when field data is aggregated. The differences are best explained with the aid of a diagram (Figure 3.1) showing a skewed distribution where the mean, median and mode are all different.

The *median* is defined so that it is equally likely that the true figure is above or below this estimate. This definition fits with the above definitions of low/high as P90/P10 and is equivalent to P50, so easy to reconcile with current conventions. Overestimation and underestimation are each equally likely - the median does not account for the possibility of a particularly large or small outcome, if the probability distribution is asymmetric. This may be preferred by small companies in possession of only one oil field, who are risk-averse and cannot afford to develop a field on the basis of a small probability of large returns, so prefer greater certainty.

The statistical *mode* is defined as the most probable figure or range of estimates, or more intuitively the highest point of the distribution. By definition the mode is the most likely figure to be "correct" (for the actual figure to fall within a range containing the mode rather than in any other equally-sized range of estimates). As with the median, the mode is not significantly affected by small probabilities of particularly large or small outcomes. Thus again this is a more suitable estimator for use when risks need to be minimised, or on the field level rather than higher levels of aggregation.

The statistical (arithmetic) *mean* is defined as the average or expected figure if many choices were made in the same situation. If this is used consistently over many fields, it should be the most accurate predictor of actual reserve volumes. However, it may not be the most accurate predictor for an individual reservoir or field. Depending on the shape of the distributions, use of the mean estimate may be more likely to under- or over-estimate reserves. However, due to the magnitude of the under/over-estimations, the regional total should still be well-predicted. For example if there is a small probability of extracting a very large amount of oil, then the mean will be skewed by this. If the estimation is performed many times for fields/reservoirs of the same characteristics, although the mean will overestimate in more cases than it underestimates, it will give an unbiased estimate of the total volume. This may be preferred by large companies in possession of a large number of fields/reservoirs, who are less affected by the risk from any one but are interested in accurately forecasting total reserve volumes over a large portfolio. It is also the sensible estimator to use in assessment of global reserves, if we are interested in an accurate figure rather than a conservative one.

In the literature there is considerable confusion regarding whether different 2P estimates should be interpreted as a mode, a median or a mean. In both probabilistic ("50% probability of being exceeded") and deterministic ("as likely as not") definitions, there is an implicit choice of the median; however, in working with these definitions they are often added arithmetically, an approach that is only valid if they represent mean estimates (see below). This would represent a significant issue if the statistical distributions were skewed enough that the mean and median were very different. It is not clear from the data available whether or not this is the case.

It is commonly assumed that fields within a particular geological region follow a *lognormal* size distribution, in that a frequency plot of the natural log of field sizes approximates a normal distribution (Arps and Roberts, 1958; Drew, 1997; Mcrossan, 1969). If this is the case, then the mean and median estimates of regional reserves are likely to be significantly different – with the median lying *below* the mean. The appropriate form of the size distribution is a topic of controversy and the observed lognormal size distribution of many regions may result in part from smaller fields being underrepresented in the sample because they are not economic to develop (Attanasi and Drew, 1984; Drew, 1997; Drew, *et al.*, 1988). But this would not affect the conclusion that the mean and median reserve estimates for the region are likely to be different.

However, if the data have been collected in such a way that the estimators themselves (accidentally or regardless of the definition) estimate the mean rather than the median, then there may be (an inadvertent) justification for identifying the 2P estimates with the mean. Some empirical data on the retrospective accuracy of estimation is shown in Section 3.3.4, although again the results are not conclusive. This is an important point to clarify in future work because if the median is being added incorrectly and if the probability distribution is skewed to the left (Figure 3.1) then aggregate P50 estimates could significantly underestimate true recoverable volumes (Pike, 2006).

3.3.3 Probabilities cannot be added together

A common error with statistical distributions is the assumption that probabilities can simply be added together. In fact this is only the case for certain probability distributions and in general it is necessary to consider separately the shape of each distribution and the shape of the resultant when they are summed (Cronquist, 1991; Jung, 1997; Pike, 2006; Ross, 1998).

For example, suppose one company owns reserves R1 which are estimated to have $(P10, P50, P90) = (20, 10, 1)$ Gb (billion barrels) and another company owns reserves R2, also with $(20, 10, 1)$ Gb, and the two companies then merge. It is *not* then generally true that the new company will have reserves $(40, 20, 2)$ Gb - this is in fact an *underestimate* of the true P90, an *overestimate* of the true P10, and will only be a correct estimate of the P50 if this is equal to the mean, rather than the median.

Pike (2006) provides an intuitive explanation of why the addition of P90 estimates lead to an underestimate of aggregate reserves with the example of two dice. If a single dice is thrown, the probability of the outcome exceeding one is 83% (5 out of 6). In other words, the P83 figure is 1.0. But if two dice were thrown, the probability of the outcome exceeding two is 97% (35 out of 36). So the P97 figure is 2.0. The corresponding P83 figure is 4 (6 out of 36), or twice the simple arithmetic aggregation of the two individual P83 figures. Hence, by simply adding the individual P83 figures, the probability of the combined score exceeding two would be significantly underestimated (the probability is actually 97% and not 83%). In a similar manner, the sum of the 1P (P90) estimates of the oil reserves of two fields would be an

underestimate of the actual 1P figure for the two fields combined.¹ Box 3.1 gives an alternative illustration using a continuous probability distribution.

Box 3.1 What is the “best” estimate?

Consider the incomes of a population of a developed country. There are some people who earn very little, a lot of people who earn a middling amount, and a very few very rich people who earn astronomical amounts. The *mode* of this distribution is the most common income bracket, which is likely to be middling. The *median* will be the income of the person whom half the population earns less and half the population earns more - again, probably quite a small figure since there are a lot of people earning a small amount and only a few people earning a large amount. The *mean*, on the other hand, is likely to be significantly larger, because one football player earning a million pounds a year “balances out” fifty people each earning £20,000.

So, the choice of “best” estimate depends on what we are interested in knowing. If we wish to calculate the likely income in twenty years' time of a child picked at random, then we may get a more representative estimate by using the *median*, or P50 value. On the other hand, if we would like to know the total future contribution to the economy of all the children born in the country this year, then we would get a better estimate of their future earnings by using the *mean*.

Similarly, the “best” choice with which to define reserves and subsequently predict future oil production will differ depending on who is making the estimate and for what purpose they intend to use it, in particular the level of aggregation. For this reason the use of a median is common for individual fields, but the mean may be more appropriate when considering global reserves.

The difficulties in aggregating reserve estimates are of particular importance for the P90 figures since these are most widely quoted. Assume first that the two sets of reserves are completely independent. In that case, to find the P90 value we must consider the probability distributions of each set separately. There is a 90% chance of the first set R1 exceeding 1Gb and an *independent* 90% chance of the second set R2 exceeding 1Gb, which we can write as

$$P(R1 \text{ exceeds } 1 \text{ Gb}) = 0.9$$

$$P(R2 \text{ exceeds } 1 \text{ Gb}) = 0.9$$

However, when considering the sum, we could also exceed 2Gb by having one reservoir perform slightly worse and one reservoir a lot better. Thus, the chance of the total exceeding 2Gb is:

$$P(R1 \text{ exceeds } 1 \text{ Gb}) * P(R2 \text{ exceeds } 1 \text{ Gb}) +$$

¹ Although helpful, this example is strictly incorrect because the “P83” of one die (the number which has an 83% or 5 in 6 chance of being exceeded) is not well-defined and could in fact be any number between 1.0 and 1.9999. This error in an otherwise accurate paper is a good illustration of the confusion and difficulty that may be engendered by the use of statistical concepts.

$$\int [P(R1 \text{ exceeds } 1 \text{ Gb by } X) * P(R2 \text{ falls short of } 1 \text{ Gb by less than } X)]dX$$

$$=0.9*0.9 + \text{a complicated integral}$$

The second term represents the degree of overlap of the two distributions. Even if a much-simplified choice of probability distribution causes the second term to be 0, the probability of both reservoirs R1 and R2 independently exceeding 1Gb is only $0.9 \times 0.9 = 0.81$, but the total probability of the sum $R1 + R2$ exceeding 2Gb is greater than this because it is possible for one reservoir to be lower while the other is higher. A simple summation (which gives the probability of $R1 + R2$ exceeding 2Gb as 0.9) may be an over or underestimate according to the shape of the distributions. If a normal distribution is assumed, then it will be an underestimate.

Alternatively, it may be the case that the two reserves are not completely independent (eg, they are part of the same geological formation; they use the same operating equipment; development decisions are made in parallel). For example, if R1 and R2 are close by, share a similar geological environment, and are developed in parallel, then it is likely that they will ultimately yield similar production characteristics. If one is overestimated in the planning stage the same assumptions probably also caused an overestimate of the other. In this case the above calculation is complicated by a weighting indicating how closely the two distributions are linked.

This is important because at *every stage* of aggregation of reserves data it is usual for the figures simply to be added together. When P90 reservoir data is aggregated to a whole field, field data to a whole company or country, and national data to global estimates, each time there is a systematic underestimation of the actual P90 which would have been calculated from a consideration of the full probability distributions. Each addition increases the degree of underestimation, with the result that the global estimates are likely to be the most biased. Hence, not only do P90 estimates provide a conservative estimate of likely recoverable resources, but the degree of conservatism is further reinforced by the aggregation process that is normally employed. The result is likely to be a set of numbers which significantly understate the amount of oil likely to be produced.

The effect of aggregating P10 estimates will be to overestimate the regional total, while the effect of aggregating P50 estimates will depend on the shape of the probability distributions. These will vary from one circumstance to another and are not well enough characterised to conclude either way. The only unbiased estimator on aggregation is the mean, which is not widely used and does not necessarily correspond to published 2P figures.

3.3.4 Deterministic terminology is inconsistently matched to probabilistic figures

There is common agreement that where the term “proved” is used, it should correspond to P90 on the probabilistic scale (SEC, 2008; SPE, 2007; UN, 2004). However, one study of Canadian oil field re-evaluations (excluding the phenomenon of reserves growth, which is considered separately by Thompson and Speirs (2009) suggests that the *de facto* definition of “proved reserves” as used by estimators is in fact closer to P60 (Jung, 1997), and a further study using US data suggests P65

(Laherrère, 2001). Large URR revisions of up to 70% are also shown by Speers and Dromgoole (1992) to occur commonly in proved reserve estimates for North Sea fields - and in both directions (Figure 3.2). Although the small dataset prevents a strong conclusion, it does not appear that 90% of estimates are exceeded. There are various comments to make on these observations:

- If there were a reliable way to estimate the systematic error and match up deterministic with probabilistic terminology it would aid the task of estimating true reserves figures.
- However, for countries where field data is not reported, this analysis cannot be performed. Aggregate figures are already shown to be inaccurate for reasons other than systematic errors in reporting.
- Countries and professional bodies differ significantly in reporting standards (see Section 4), so any systematic error found to exist in one dataset is unlikely to be applicable to other figures. However, if the Canadian experience was followed in other jurisdictions, the net effect would be to reduce the degree of underestimation in both individual and aggregate P90 reserve estimates.

Perhaps the only reasonable conclusion one can draw is that even when the terminology is precisely defined, estimators are not good at accurately estimating reserves, leading to large revisions in both directions as information is gathered over the lifetime of a field. The implications of this inaccuracy for global reserve estimates are ambivalent: if there is systematic error in one direction, then there will be very large errors introduced upon aggregation of field and country level data, but if the errors are random and evenly distributed, then they will effectively “cancel out” and the aggregate data may still be accurate even though field-level data is unreliable.

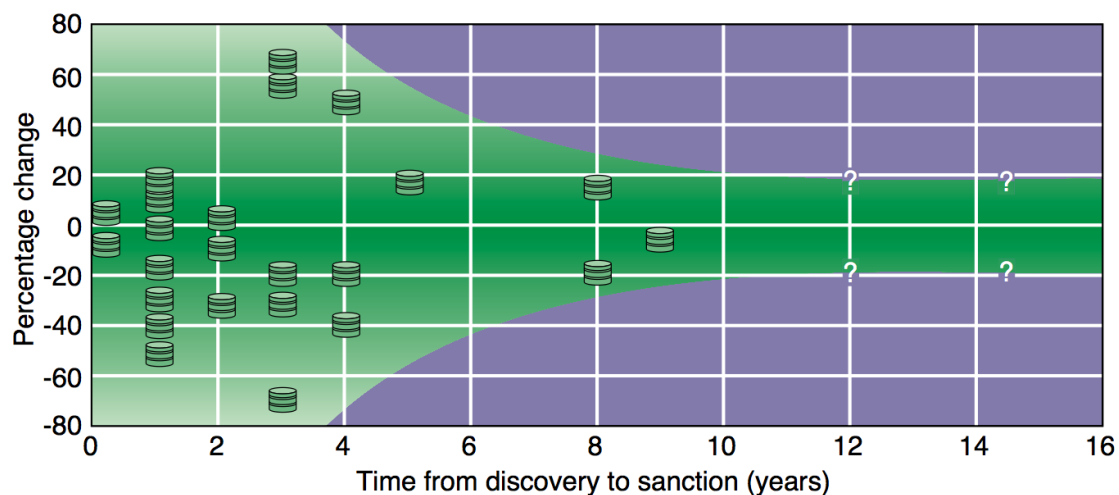


Figure 3.2 An analysis of proved reserve revisions in the North Sea. This demonstrates again the very large revisions in both directions which may be made to a field in the years following discovery. Source: Speers and Dromgoole (1992).}

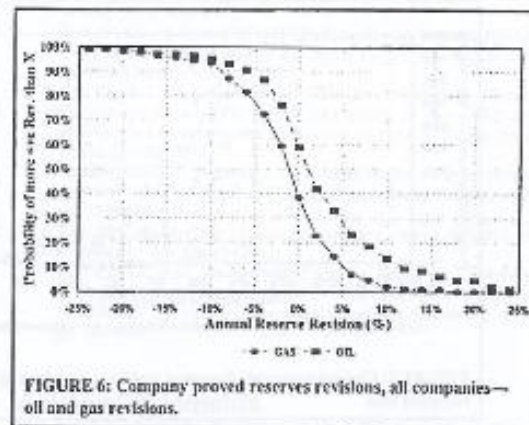
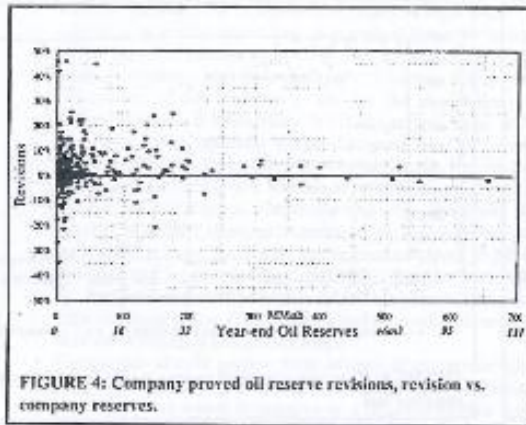


Figure 3.3: An analysis of oil field re-evaluations suggesting that “proved” actually corresponds to about P60 by consideration of Canadian data. Similar analysis of US data by Laherrère suggested that “proved” = P65. Source: Jung, 1997.

4 Reserve classification schemes

Most reserve classification schemes are indirectly based on that proposed by McKelvey of the United States Geological Survey (USGS). The “McKelvey Box”, shown in Figure 2.1, classified petroleum resources along two dimensions: a) the level of geological knowledge (undiscovered resources or discovered reserves, and then by degree of certainty in discovered reserves); and b) the economic viability of recovery. This is based on the terminology used in a report from the American Petroleum Institute (API), which published annual US reserve data before this function was taken over by the US Department of Energy (McKelvey, 1972).

Cronquist (1991) compares a number of different current reserves classification systems, showing in general a tendency to use McKelvey's two dimensions of geological knowledge and economic viability, and a similar terminology, although with differing definitions. “Proved” and “probable” are identified in many systems with 90% and 50% probability of being exceeded. “Possible,” where used, is less often defined statistically and in some cases corresponds to 10% probability of being exceeded and in others is left as anything under 50%. Of the 25 classification systems considered, 19 used the terminology “proved”, 16 used “probable” and 13 “possible”. Nine of the schemes used probabilistic definitions of the terms but these do not agree; for example, the Australian Minerals and Energy Council system proposes 93/60/5% whereas all others agreed that “probable” should be a median value of 50%. A disagreement is indicated in Denmark where two systems are given, one marked “producing companies' preference” and one “government preference”.

The details of the majority of these classification schemes are not discussed here as they are only used by the proposing agencies/countries. However, the above description gives some idea of the disparity in the definitions that are currently in use, both between countries and even within the same country. This suggests that the aggregation of data from different sources to give regional or global reserve estimates is highly problematic.

With the above in mind it is easy to understand why the petroleum industry has attempted to standardise definitions at various points in time. Each professional body and organisation with an interest in petroleum had its own set of working definitions, including the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC), and the Society of Petroleum Evaluation Engineers (SPEE), among many others. The different definitions emphasise different factors according to the interests and expertise of the relevant organisations. Recently, the above four organisations have combined their expertise into joint proposals for a Petroleum Resources Management System (PRMS) (Section 4.3 and SPE (2007)).

The following sections summarise four of the most important reporting standards, namely: the US Securities and Exchange Commission (SEC) rules, the Petroleum Resources Management System (PRMS), the UN Framework Classification of Energy and Mineral Resources (UNFC-EMR) and the classification scheme used in the UK.

4.1 SEC definition: legally required disclosure for US listed companies

The US Securities and Exchange Commission (SEC) was created after the stock market crash of 1929 and ensuing depression, to “*protect investors, maintain fair, orderly, and efficient markets, and facilitate capital formation*” (SEC, 2004). They set a series of rules and standards for information disclosure including the disclosure of oil reserves owned by companies listed on the New York Stock Exchange. Although this does not include national oil companies, the majority of large international oil companies are listed in the US and therefore this regulation is particularly important for reserve disclosure worldwide.

The current regulations (until December 2009) require only a disclosure of “proved” reserves, which are defined as “*the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions*” (SEC, 2008).

The above definition does not encompass “unconventional” sources of oil such as tar sands and oil shales, which may contribute very large volumes of recoverable hydrocarbons in areas such as Canada and Venezuela. There is also no discussion of probability beyond the assertion of “reasonable certainty”, which is usually identified with 90% probability in the literature (although, as we have remarked above, this identification may not in practice be accurate). The restriction to existing economic and operating conditions is also restrictive as it makes no allowance for anticipated changes in those conditions. Finally, only reserves “*...supported by either actual production or conclusive formation test*” can be declared proven for any field. Since only those parts of a field within production range of a well can be included in official reserves statistics, the size of fields appears to grow as more wells are drilled – leading to “reserves growth” over time that is largely an artifact of the restrictive definition.

However, due to significant changes in technology and in company practice since the last review of rules in this area (1978), the SEC has conducted an extensive consultation and proposed a modernisation of the oil and gas reporting requirements, which is due to become effective from January 2010. The key updates are:

- update of definitions related to oil and gas reserves (see below);
- provisions that permit the use of new technologies to determine proved reserves, even in the absence of fluid contact to existing wells, provided those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes;
- disclosure of technologies used to establish reserves;
- inclusion of unconventional reserves such as oil sands, together with coal and oil shale reserves that are intended to be converted into oil and gas ;
- optional disclosure of probable and possible reserves;
- optional disclosure of reserves' sensitivity to price;
- use of year-average price rather than year-end price to report valuations;
- more extensive auditing requirements.

The definition of “proved reserves” is updated to specify that, where probabilistic methods are used, there should be at least a 90% probability that the quantity recovered will equal or exceed the estimate. Similarly, “proved and probable” and “proved, probable and possible” reserves are identified as probabilities of greater than 50% and 10% respectively. The phrase “reasonable certainty” continues to be used in other definitions but is clarified to mean a greater than 90% probability when probabilistic methods are used. This all represents a move towards the SPE set of definitions (see below), though there remain some inconsistencies in the economic conditions required. Disclosure is required country by country for those which contain more than 15% of a company's total reserves, and field by field for those which constitute more than 10%, except in jurisdictions where such disclosure is prohibited.

Other countries also have internal legal disclosure obligations, with which operators are required to comply. However, none exerts as much international influence as the US standard. This update represents a useful step towards standardisation, although it is very unfortunate from the perspective of global reserve estimation that the publication of 2P reserve data remains optional. At the time of writing, it is unclear how many companies will declare 2P reserves and there could well be disincentives to do so.

4.2 SPE classification: becoming standard

The SPE (2007) classification set out in their Petroleum Resources Management System, classifies petroleum by geological and economic certainty, again following McKelvey (1972). The economic divisions into “reserves”, “contingent resources” and “prospective resources” (see Figure 4.1) are defined as follows:

- **RESERVES:** *“those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward, under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining.”*
- **CONTINGENT RESOURCES:** *“those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.”*
- **PROSPECTIVE RESOURCES:** *“those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.”*

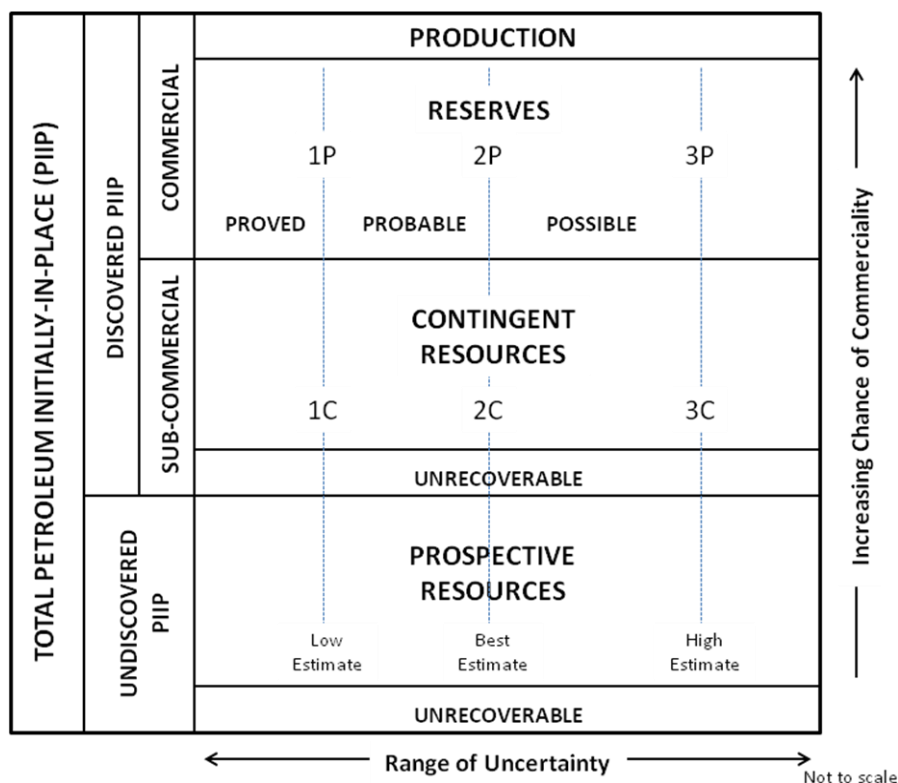


Figure 4.1: The SPE classification scheme follows McKelvey (1972) in dividing reserves and resources by geological certainty and economic feasibility of extraction.

Each of these categories is further subdivided by range of geological uncertainty: 1P/2P/3P in the case of reserves, a similarly-defined 1C/2C/3C in the case of contingent resources, and “low”/”best”/”high” estimates for prospective resources. The terminology of “proved, probable and possible” is used but the classification allows for the use of either deterministic or probabilistic estimates. In the former case, a series of suggested descriptions are given; in the latter case, P90, P50 and P10 are to be used as the corresponding figures. The observations of Section 3.3.4 above suggest that the same guidelines may lead to different estimates if a different method is used. This is a major source of inconsistency in the SPE framework.

The SPE recommendations on aggregation of reserve estimates suggest two acceptable methods of aggregation: arithmetic summation of estimates by category and statistical aggregation of uncertainty distributions. Due to the significant difference in results obtained by these methods (Section 3.3), the SPE recommend that *“for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. Results reporting beyond this level should use arithmetic summation by category but should caution that the aggregate Proved may be a very conservative estimate and aggregate 3P may be very optimistic depending on the number of items in the aggregate. Aggregates of 2P results typically have less portfolio effect that may not be significant in mature properties where the statistical median approaches the mean of the resulting distribution.”*

The SPE PRMS system is widely used within the petroleum industry by engineers and evaluators and the revision of the SEC reporting guidelines described above will bring them more into line with the PRMS definitions (IEA, 2008; SEC, 2008; 2009). Thus it seems most likely that if global harmonisation of definitions is ever achieved it will be by development or refinement of this classification scheme.

4.3 UNFC-EMR suggestion: not widely used

As an example of a competing classification scheme, we consider one put forward recently as an extension to petroleum of a more general mineral resource reporting system. The United Nations (2004) Framework Classification of Energy and Mineral Resources (UNFC-EMR) uses a three-dimensional classification by economic viability (E), field project status (F) and geological assessment (G). This is similar to the choices made by the SPE classification, although the SPE conflate categories F and G (perhaps on the basis that any resource which is geologically well-endowed and economically feasible will go ahead regardless of other factors). The UN scheme is here more explicitly divided up by presentation on a three-dimensional graph (see Figure 4.2).

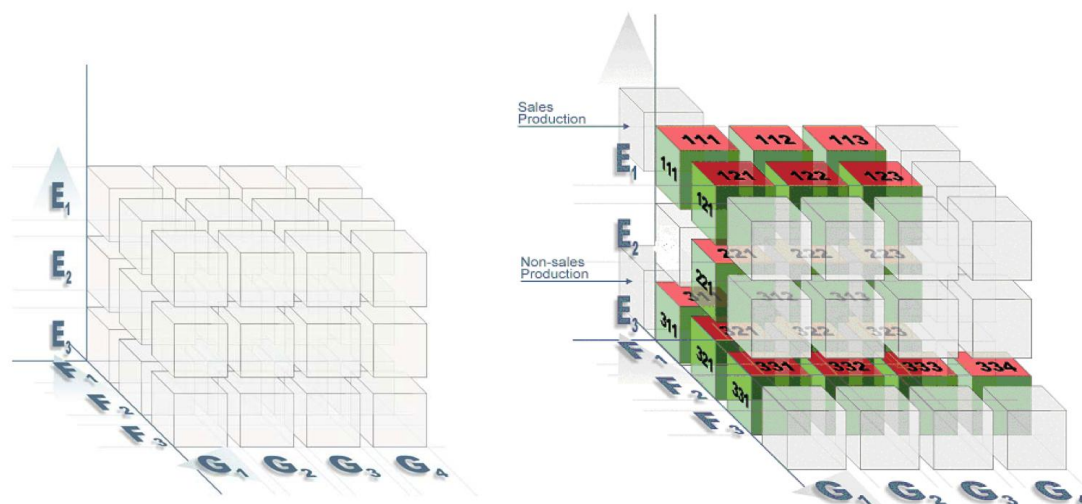


Figure 4.2: UNFC classification scheme. Left: all possible categories. Right: those which are applicable to petroleum resources. On the right diagram there are boxes “off the scale” which are “F0” - these correspond to produced oil which is either sent to market (sales production, E1 F0), or lost during the extraction and refining process (non-sales production, E3 F0).}

Sub-classes are then referred to by their categorisation in each dimension - for example, a well-developed project with good economic viability and well-characterised geology would be E1 F1 G1. The UNFC document is applicable to different types of mineral exploitation and is more general than the SPE, so it is important to note that not every sub-category may be appropriate for the case of petroleum extraction (Ahlbrandt, *et al.*, 2003). For example, since geological appraisals are almost always the first step in a project development, which will not go ahead until the geology is well understood, there is unlikely to be a need for the E1 F1 G3 category. The aim of this classification is to reduce the reliance on descriptive

labels for categories and replace them with systematic and well-defined numerical definitions.

The McKelvey box (Figure 2.1) can be mapped into the E-G plane of this classification. Reserves are confined to the E1 F1 categories, with categories G1, G2 and G3 corresponding roughly to “proved”, “probable” and “possible” respectively. However, the UNFC does not recommend use of this “*broader, and more ambiguous*” terminology.

The United Nations (2004) make no comment on how reserve estimates made in the various categories should be aggregated for the purposes of reporting or to produce larger scale figures. Although the system is widely used for classification of other mineral resources such as coal and uranium, it appears to be used more by academic/research institutions than by industrial/commercial bodies, and even then usually also with reference to the SPE scheme (Ahlbrandt, *et al.*, 2003).

4.4 The UK: an example of non-US government reporting standards

In the United Kingdom, data are made publicly available on a yearly basis for all fields within the country's jurisdiction. The UK reserves classification scheme is superficially very similar to those of the US and the SPE:

- RESERVES: “*discovered, remaining reserves which are recoverable and commercial. Can be proven, probable or possible depending on confidence level*” (as described below).
- POTENTIAL ADDITIONAL RESOURCES: “*discovered reserves that are not currently technically or economically producible.*”
- UNDISCOVERED RESOURCES: “*undiscovered potentially recoverable resources in mapped leads*” (structures which have been geologically mapped and are considered geologically feasible to contain hydrocarbons).

It might be considered nit-picking to point out that the first definition is self-referential, as it is reasonably clear what is meant. Reserves are further categorised, using the SPE terminology, as being “proven,” “probable,” or “possible” based on confidence levels as follows:

- PROVEN: “*Reserves which on the available evidence are virtually certain to be technically and commercially producible, i.e. have a better than 90% chance of being produced.*”
- PROBABLE: “*Reserves which are not yet proven, but which are estimated to have a better than 50% chance of being technically and commercially producible.*”
- POSSIBLE: “*Reserves which at present cannot be regarded as probable, but which are estimated to have a significant but less than 50% chance of being technically and commercially producible.*”

Again, there is the identification with probabilistic figures of 50% and 90% probability. The figure for “possible” reserves is defined descriptively as

“significant,” rather than probabilistically, which is inconsistent with other definitions but may be easier for interpretation by estimators.

There is also some confusion regarding the aggregation of these figures. The website of the UK Department of Energy Climate change (DECC) states that, in order to produce a table of UK oil reserves: *“Proven, probable and possible reserves for a large number of individual fields have simply been summed to give the totals shown. There is, thus, a much smaller likelihood that the true figure for total oil reserves is outside the range of estimates than when considering probabilities for an individual field.”* As pointed out by Cronquist (1991), Rose (2007), and the SPE (2007), this procedure systematically underestimates true 1P reserve volumes at the aggregate level and overestimates 3P. In fact, it is highly likely that the true figure for total 1P oil reserves is above the range of their estimates, and that the true figure for total 3P reserves is below the range.

5 Why reserve estimates change over time

Changes in reserve estimates over time may be due to a number of different reasons. Remaining reserves decline as oil is produced but may also increase as new discoveries are made, existing fields are developed, new technologies employed and remaining reserves re-evaluated. The actual change in declared reserves from year to year will depend upon the balance between these various factors. The term *reserve additions* is often used to describe this process, although in some years there will be ‘reserve subtractions’. The change over time also depends on the time between revisions, so for example in some countries we see reserve estimates remaining the same for a number of years before a large re-evaluation.

The term *cumulative discoveries* may be used to refer to the sum of cumulative production and declared reserves at a particular point in time. Depending upon the definition of reserves that is being used, this could refer to either cumulative 1P, 2P or 3P discoveries. The slightly misleading term *reserve growth* refers to the increase in cumulative discoveries over time (a better term would be cumulative discovery growth). This reserve growth may result from a variety of reasons, including initial underestimation of recoverable reserves, and is discussed in detail in a companion report (Thompson, *et al.*, 2009). The difference between cumulative discoveries and the URR for a field or region is that an estimate of URR should also include an estimate of the future reserve growth and (at levels of aggregation higher than field scale) new discoveries.

5.1 Production

Every year some amount of oil is extracted from the reservoirs and this should decrease the total remaining reserves figures by an amount equal to the extracted volume. However, it should not affect the estimates of cumulative discoveries, since oil is simply being shifted from the reserve category to the produced category.

5.2 New discoveries

New fields will be discovered and subsequently brought into production, thereby adding to the reserve estimates for a region. In terms of the PRMS (Figure 4.1), this may be interpreted as the conversion of prospective resources into reserves/production. Note that a discovery of 1 mb P90 reserves in a new field will increase the P90 reserves of the whole region by *more than* 1 mb for the reasons explained above.

5.3 “Reserves growth”

Estimates of cumulative discoveries from known fields will also tend to increase as a result of improved recovery factors, the physical expansion of fields, the discovery of new reservoirs within fields, the re-evaluation of cumulative discovery estimates in the light of production experience, and other factors (Drew and Schuenemeyer, 1992; Gautier, *et al.*, 2005; Klett and Gautier, 2005; Klett and Schmoker, 2003; Morehouse, 1997). In terms of the PRMS classification, this may be interpreted as the exploitation of more uncertain reserves (2P and 3P) together with the conversion of contingent resources into reserves/production. If cumulative discovery estimates are based upon 1P reserves, a large part of the observed reserve growth may be attributed to the conservatism of the initial estimates. In contrast, if they are based upon 2P reserve

estimates, other factors such as technical change may play any more important role. However, the relative contribution of different factors to reserve growth is not easy to assess and remains a topic of considerable dispute (Klett, 2004). This issue is discussed in more detail in Thompson and Speirs (2009).

5.4 Re-evaluation

“Re-evaluation” of 1P, 2P or 3P cumulative discovery or reserve estimates may in theory be either upward or downward, resulting from a more accurate assessment of the productive capacity of a field. In some cases, however, re-evaluation appear to have been undertaken in part for political reasons, typically resulting in large increases in the estimated reserve volume. For example, Figure 5.1 shows the re-evaluation of reserves by OPEC countries following the decision in 1982 (informally) and 1983 (formally) of the OPEC Secretariat to link production quotas to the published reserves figures (Salameh, 2004). This provided an incentive for countries to be optimistic about their reserves, and this resulted in an increase of 80% to OPEC's proven reserves and a total increase of 300Gb to global proven reserves, representing nearly 30% of the global total in 1990 (IEA, 2008; Sandrea, 2003). Because there may have been some tactical understatement of reserves prior to this date, the conclusion cannot be drawn that post-1990 figures are all overestimates, but in the absence of third-party verification and access to the relevant data, it is difficult to check the accuracy of the figures. A measure of the confusion surrounding this area is that, as Bentley *et al.* (2007) point out, “*for the main Middle East OPEC countries, their 2P reserves held by industry are considerably smaller than their public domain proved [1P] reserves*”. Given the accepted definitions, it is clear that one or the other estimate must be wrong by a very significant margin.

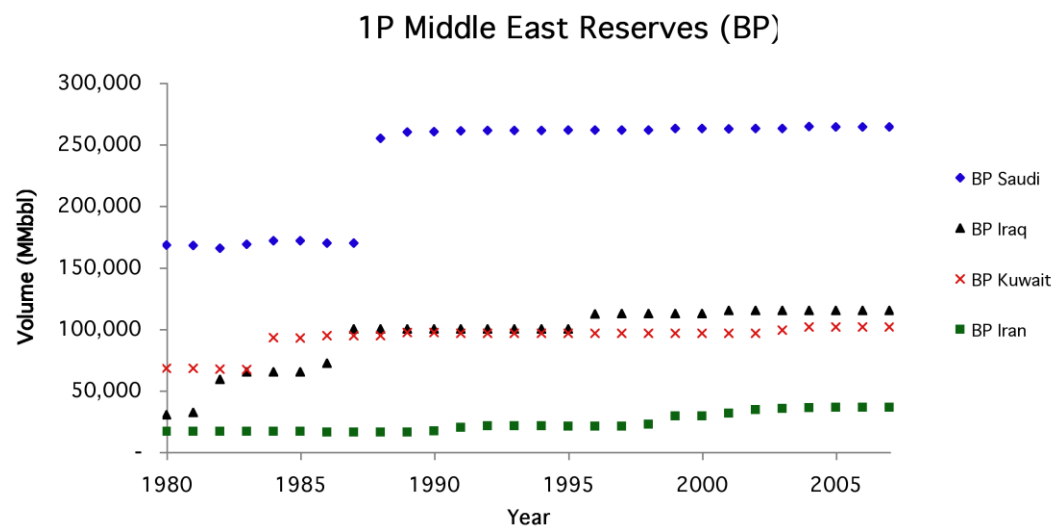


Figure 5.1: Published 1P reserves of four OPEC countries (Saudi Arabia, Iraq, Kuwait and Iran) over the period of reevaluation, as reported in the BP Statistical Review of World Energy (2008). The increases in “proved reserves” did not result from new discoveries.

Less commonly, it may be necessary for a country or company which has previously overstated reserves figures to correct them downwards. This was famously the case for Shell, which was forced to publish a downward revision of proven oil and natural gas reserves by the equivalent of 3.9 billion barrels of oil (20% of their reserves) in

early 2004. This is not a decision the company would have taken lightly, as it caused an immediate fall in the share price and the subsequent resignation of various senior executives. Such a large revision serves to highlight the uncertainty in reserves figures even at a high level within the oil industry and the sensitivity that invariably surrounds them. That Shell's own employees cannot agree to within 20% how much oil there is in their own reserves, with access to the latest technology and the best experts, is a good measure of the level of uncertainty surrounding the estimation process and (without making implications about Shell) the degree to which it could be influenced by financial or political incentives.

A further example of downward revision is the case of Mexico, which revised its reserves estimates to comply with the definitions current in the United States when it joined the North American free-trade zone. This resulted in a reduction of Mexico's "proved" reserves by a factor of three (Babusiaux and Bauquis, 2007).

5.5 Change in definitions

Another form of re-evaluation occurs when reserve definitions are changed to include or exclude categories of oil production. This can be seen in historical data produced by three reporting bodies: WorldOil, the Oil and Gas Journal (OGJ), and the BP Statistical Review of World Energy. The three estimates they produce are formed broadly on the same lines and in many cases based on the same sources. However, there are some notable discrepancies between the figures.

For example, between 1991 and 1995 the WorldOil database showed estimates of Russian reserves of about 160 billion barrels, a 170% increase on the pre-1991 and post-1995 figure which was approximately 60 billion barrels (Figure 5.2). This is due to disagreement on how the former USSR reserves classification system should correspond to the conventional terminology of "proved" reserves. The USSR system used a scale running from A, B, C1, C2, C3, D1, and D2 to E, F and G which are identified with "possible" and H, N, and P with "undiscovered". The identification of "proved" reserves is very inconsistent; Cronquist (Cronquist, 1991) describes two alternative systems in which "proved" is taken to mean either $A + B + 30\% C1$, or just the figure for A itself.

The change in WorldOil figures reflects a change from one "translation" between two reporting systems to another (and then back again). The large difference between the estimates thus produced is a strong argument in favour of a single unified standard for global reserve reporting.

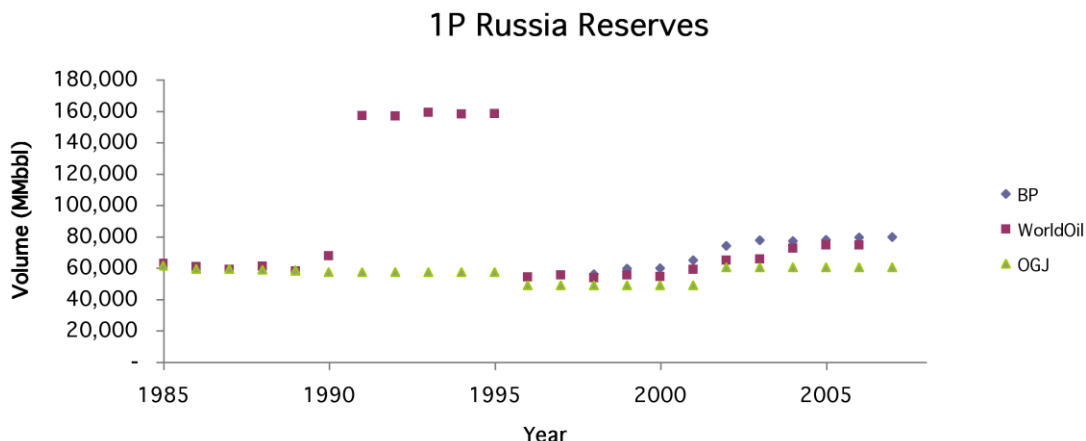


Figure 5.2: Change in Russian 1P reserves figures over time, showing the inconsistency caused by changes in definition used by WorldOil to estimate reserves volumes.

There is also disagreement between the same three sources regarding Canadian reserve estimates. The difference of over 170 billion barrels between the estimate given by the OGJ and that given by the two other sources from 2002 onwards (see Figure 5.3) is largely due to the inclusion of oil sands reserves in the OGJ “proved” estimates. There is a wider debate regarding the inclusion of such “unconventional” oil in proved reserve figures, as it has historically been excluded but is becoming increasingly important in world production. As long as both numbers (including and excluding the unconventional resource) are stated, there should be no confusion and the Canadian figures are approximately in agreement when the estimate for the tar sands is subtracted from the OGJ total. However, the numbers will differ by a large amount and it must be made very clear in all definitions what categories of oil are included.

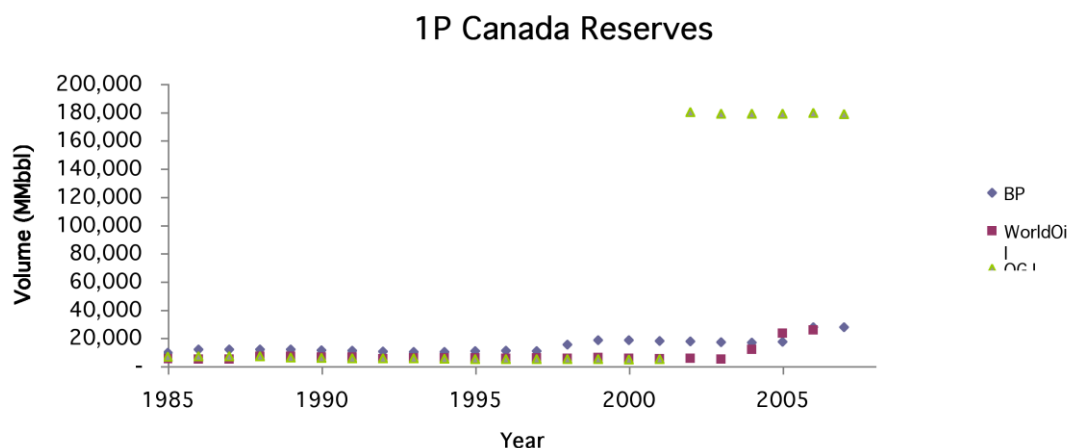


Figure 5.3: Change in Canadian 1P reserves figures over time, showing the inconsistency caused by the OGJ's inclusion of “unconventional” oil in the published figures.

6 Conclusions

The main conclusions from this review are as follows.

6.1 Definitions are inconsistent

The major inconsistency between reserve definitions is the choice of either a deterministic or probabilistic methodology. Within the class of deterministic definitions, the terms “proved”, “probable”, “possible” are widely used (Table 2.1), but the use of this language is not standardised. Various terms such as “reasonable certainty” and “virtually certain” are used, which have very subjective interpretations. Within the class of probabilistic definitions there is wide agreement that 10%, 50% and 90% probability levels are appropriate to specify when reporting reserve estimates, although other levels are proposed by some agencies.

6.2 Interpretations of the same definitions are inconsistent

Empirical evidence (Figure 7) has demonstrated that where deterministic terms such as “proved” are specified in a (probabilistic) way allowing retrospective evaluation of estimates, the actual use of the term may not match the corresponding probabilistic definition. Where a probabilistic definition is not specified, it is not really possible to quantify the accuracy of initial reserve estimates by this method, but the fact that it is impossible to check and therefore to calibrate estimation procedures means that any errors made cannot be corrected for later, so it is likely that these interpretations are even more inconsistent.

6.3 Uncertainty is not adequately described

Deterministic estimates do not provide any indication of the uncertainty in the estimates of reserves that are expected to be produced. From the discussion of how reserve volumes are calculated (Figure 3) we can be sure that there are large uncertainties in any estimate of the oil originally in place due to the impossibility of measuring the relevant physical and geological characteristics of a heterogeneous field sufficiently accurately. Further uncertainty is introduced in making the estimate of how much is technically possible and economically feasible to extract, and again when aggregating results for individual fields to large areas. However, deterministic estimates are often stated to three or even four significant figures, implying an uncertainty of just 1 or 0.1%! This is clearly unjustifiable.

Probabilistic estimates are better, because the definitions themselves include an acknowledgement of the uncertainty in the estimation. However, there is still a tendency to quote numbers to 3 significant figures.

6.4 Probabilistic definitions are needed to ensure accountability

Probabilistic definitions do not lessen the intrinsic physical uncertainty in making an estimate but they can eliminate the possibility of deliberate bias for political or financial gain, or accidental bias due to misinterpretation of language or human error (Rose, 2007). Because probabilistic definitions allow retrospective evaluation of the

accuracy of reserve estimates, errors in estimation can be identified. This may be used to calibrate later estimates, increasing the accuracy of results, or by a third party to ensure that reserve definitions are being adhered to. This level of accountability is not achievable with deterministic definitions.

6.5 Aggregate reserve estimates can be highly misleading

Deterministic estimates cannot be aggregated by simple addition, because the terminology used to describe them represents an underlying distribution of probability which is not removed by choosing to describe it qualitatively rather than quantitatively. Due to this probability distribution, aggregation of 1P estimates causes an underestimation of total proved reserves and aggregation of 3P estimates causes an overestimation of total proved, probable and possible reserves. Aggregation of 2P estimates correctly interpreted as the median introduces quantitatively less error, which may be positive or negative depending on the underlying probability distributions. If the 2P estimates are (incorrectly) interpreted as the mean estimate, then there will be no bias upon aggregation.

6.6 Where available, 2P reserve estimates may be more useful than 1P

Given that the aggregation of 2P estimates introduces less systematic error than the aggregation of 1P estimates, they should be preferred when assessing aggregate and especially global reserve data. However, the aggregation of the 1P estimates can at least be said to provide a good lower bound for total reserves, whereas the direction of the error in the 2P estimates is unknown until the probability distribution can be found. For some countries, the official estimates of 1P reserves are greater than the industry estimates of 2P reserves. This suggests significant misreporting (Bentley, *et al.*, 2007), but in the absence of third-party auditing it is not clear which figure is more reliable.

6.7 Standardisation is underway but incomplete

There has been very little progress in standardising and harmonising the dozens of reserve definition schemes that are in use around the world. Perhaps the most promising development is the Petroleum Resources Management System put forward by a group of industrial and academic bodies led by the Society of Petroleum Engineers. This is mainly deterministic in character but does include a suggested correspondence with probabilistic figures (though these are not mandatory under the PRMS). The system is now used by many agencies including some national and international oil companies and has had considerable influence on accounting standards. However, it is by no means universal and as it allows for completely deterministic reserve declarations, consistency across estimates cannot be checked.

6.8 Choice of definition significantly alters reserve estimates

The choice of definition (Figure 12) and the coverage of different categories of oil (Figure 13) can lead to very different reserve estimates for a region. This is a major argument in favour of standardisation of coverage and definitions in a way that will allow retrospective evaluation and calibration of estimates. It also suggests that global reserve estimates will depend significantly on the choice of definitions used, so for

the purposes of evaluating trends and estimating future production it will be necessary to think carefully about what definitions are the most appropriate (Bentley, *et al.*, 2007). The choice of definition also significantly alters the potential for reserve growth and methods by which this may be estimated.

6.9 Meaningful definitions are needed for meaningful estimates to be produced

Given the observations above, the current definitions must be concluded to be very unsuitable for the purpose of forecasting future global oil supply. To produce meaningful estimates of global oil reserves will require standardisation (or at least harmonisation) of reserve definitions and of their interpretations, which can only be done with probabilistic definitions. Major barriers to this include the minimal current accounting standards, the widespread lack of statistical expertise on the part of those involved in estimation, and the reluctance of many countries to accept a standard and to publish transparent and auditable estimates. Standardisation is underway but proceeding very slowly. It is likely that current estimates of global and the 1P reserves are significantly understated, and that aggregate estimates of global 3P reserves are significantly overstated. The best estimate of global future production would come from the use of 2P reserve data, but it is currently not possible to say whether this is likely to be an under- or overestimate. Further work should, however, be able to reduce uncertainty at least in those areas where field data is available to assess estimation success retrospectively.

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