

# Probability and the petroleum system: Issues for investors in the upstream oil and gas industry

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## Abstract

The oil and gas industry is now engaged in a dynamic re-structuring. A combination of globalisation, energy sector reforms, political shifts leading to an opening up of new opportunities, together with an intensive search for replacement of produced hydrocarbon reserves, has presented not only challenges, but also significant opportunities. Upstream investment is a high-risk, high-cost business. Value creation in such an environment demands a detailed understanding of the risks and uncertainties. Cost containment, although a vital component of any investment programme, cannot, by itself, grow the business.

Some of the issues that are fundamental to any upstream investment programme include: technical uncertainties (chance of success, estimation of potential reserves sizes); exploration and development costs; and detailed assessment of risk versus return (risk-based evaluations of key economic criteria such as net present value, discounted return on investment, payback and maximum negative cash flow).

A working petroleum system consists of a hydrocarbon source rock, suitable geological structures, trapping strata, reservoir rock, and migration pathways from source to traps. Probability-based economic models consistently demonstrate that predicted hydrocarbon reserves size ranges and chance of commercial success have by far the largest effect on net present value estimates. Economic analysis of petroleum systems and associated drilling prospects *assumes* unbiased, quality technical input. For this reason, third-party technical peer reviews are particularly recommended, to minimise the external and internal organisational biases of buyers and sellers.

Portfolio analysis brings consistency to a company's decision-making processes. Techniques are presented that not only help predict the risks, rewards and costs of the total programme, but also determine the optimum level of equity that the investor should aim for in each project. Where current equity is greater than the modelled risk tolerance of the company, value equivalence can be calculated, and equity reduced by farming out.

## Introduction

The oil and gas industry has always been deeply involved in major global political and financial events and today's exploration and production business is no exception. Since the oil price shocks of the 1970s and the surge in prices after the fall of the Shah of Iran, followed by the price collapse in 1986, the business has been in a state of dynamic flux. Some of the industry reactions to temporary price rise and falls have been myopic, knee-jerk responses, with over-compensated staff shedding and budget cuts, whereas others have been more measured, and have reflected a management cognisance of long-term trends. An example of the latter would be BP's acquisition strategy, which reflects its belief, supported by ample statistics, that the kind of field-size discoveries needed to sustain its reserves replacement programme are in increasingly shorter supply, and likely to

be in either deepwater or in the Middle East. Russia, of course, the great hope of the 90s, is the proverbial "can of worms" and has yet to deliver on its promise.

New Zealand, since the Second World War, has seen two relatively long-term exploration and production strategies: the Shell-Todd joint venture, and the state-driven activities of Petrocorp. All other players have come and gone without pursuing a persistent exploration-drilling programme. The recent Westech/Orion joint venture on the East Coast has seen a welcome return to a drilling level that recognises that multiple tests are required to have a chance of creating value, given the probability of success of most exploratory wells.

In addition, a company such as Orion, historically mainly involved in downstream activities, is itself now an equity holder in upstream activities. As such, it is well placed to be

involved in the production and sales of any discovered hydrocarbon resources.

Investment in the upstream arena takes many forms. Mainstream exploration and production companies acquire drilling acreage through government-controlled licensing rounds, which usually take the form of competitive work-programme bidding, or through direct applications such as the Acceptable Frontier Offer system in New Zealand. Auction (cash-bid) blocks are rare on a worldwide basis, although they are beloved by the U.S. Treasury. Cash-bidding on auction blocks, particularly in the Gulf Coast of the USA, and the ubiquitous overbidding in such a fiercely competitive environment, has led to a severe erosion of shareholder value over the years. These effects have been well documented by U.S. authors such as Capen *et al.* (1971). One must be cautious, however, in applying the same analogies to countries such as New Zealand, as the bid on auction blocks in the U.S. is non-refundable, whereas in New Zealand, the regulatory system has allowed significant renegotiation of commitments. A simple examination of work programmes promised versus work programmes fulfilled, would demonstrate that many blocks are relinquished well before the commitment date for serious capital expenditures. Unlike the U.S., however, money is rarely left on the table through overbidding, as after renegotiation, the actual programme carried out by the winner of a licence is often not significantly different from other players' submissions. Value destruction is, therefore, more likely to be linked to other issues, in particular the failure to recognise the risks and uncertainties involved, and the inability to fully understand the petroleum system.

Another well-used vehicle for accessing opportunities is via a farm in to existing licences. This usually takes the form of a promote, whereby the farminee pays some of the costs to the other equity holders, in exchange for a variable equity share. The mechanics of this will be discussed in a later section.

A third mechanism, which is becoming more popular as the supply of good prospects dwindles, is the merger or acquisition. Although these can seem a panacea, with the promise of cheap reserves and instant cash flows, history has shown that they hold many pitfalls for the unwary.

Key issues for investors in the upstream industry, be it through any of the vehicles listed above, include:

- technical risks and uncertainties;
- operational risks;
- exploration and development costs;
- detailed understanding of risk versus return profiles; and
- an understanding of what it takes to “play the game”.

These issues can be addressed through the use of risk and uncertainty analysis, and contestable technical advice. These techniques help to:

- assess whether the reward is worth the risk;

- develop a consistent approach to investing;
- evaluate funding levels of competing opportunities;
- forecast whether the portfolio will achieve the business objectives;
- provide a framework for continuous improvement; and
- minimise organisational bias, where the needs of individual may conflict with the needs of the organization, and where buyers and sellers have an obviously different motivation.

Uncertainties may be predictable or constrained, such as taxes, prices, drilling and development costs and operating costs; geological uncertainties, such as reserves sizes and dry-hole risk (which have by far the biggest impact on reward potential, as will be shown later); and quality of technical interpretations. These uncertainties can be reduced by the use of modern technology, such as three-dimensional seismic surveys; by the use of moderated peer reviews to ensure that the team is not just working in its technical “comfort zone”; and by modelling with appropriate risk, probability, and portfolio thinking and management techniques.

Several examples of these techniques are the subject of this paper, and are discussed in the following sections.

## The petroleum system

Understanding the petroleum system that supports the concept of a potential drilling prospect is the bedrock for any modelling of risk and reward. It cannot be emphasised enough that sophisticated analysis techniques, such as Monte Carlo simulations, are worthless if the whole premise of the prospect is flawed. This is not to say that everything must be known – it can't be, given the incompleteness of the geological data set – but that the uncertainties and risks have been competently estimated and, most importantly, accepted.

A viable petroleum system, as defined by Magoon (1988), consists of mature hydrocarbon source rock; hydrocarbon fluid or gas migration pathway(s); reservoir rock; sealing strata; and an appropriate structural trapping configuration, all of which must be present within specific geographic, stratigraphic and time limits, and which are (or have been) positioned in space and time such that a hydrocarbon accumulation results. The advantage of the petroleum system approach is that it forces us to think of petroleum geology in terms of components (source rock, reservoir, etc.); timing (trap formation, critical moment, etc.); and processes (fluid-flow, mass-transport, capillary retention, etc.), (McAlpine and O'Connor, 1998). As Carragher (1994), for example, has pointed out, even if all other elements are extremely robust, one weak link will break the chain. In addition, if the weak link is a dependent probability – for example a common active source rock – *all* prospects dependent on it will suffer the same fate. His analysis of several major oil company exploration well results indicated clearly, that on a statistical basis, observed failure rates demonstrated that “high risk” often meant “no chance”.

It is the role of the geologist, geophysicist, and to some extent the petroleum reservoir engineer, to determine the probability of successfully encountering all these required elements in any given prospect. These probabilities are independent and therefore are multiplied together to give the overall chance of success. Thus:

$$P_{\text{source}} \times P_{\text{migration}} \times P_{\text{reservoir}} \times P_{\text{seal}} \times P_{\text{trap}} = \text{Probability of Geological Success.}$$

Where prospects or other reservoir objectives share a common requisite success factor, those probabilities become dependent, and pre-drill, lead to a higher risk for each target level in multiple-objective prospects. Common factors may include the same source rock and a shared structural configuration. Of course, in the event of a discovery at the shallow level, these now-proven dependent probabilities lead to a reduction of risk for deeper targets with shared dependencies.

## Probability of success

Geological success does not necessarily make money for the investor. Initial euphoria can often lead to severe disappointment at a later date. Success for the investor means commercial success. It is important to define types of success, as each has a role to play in the exploration and development process. The three major types are:

- Geological success, defined as a stabilised flow of hydrocarbons to surface, not necessarily commercial. This is a definitive event, not affected by economic considerations.
- Completion success, defined as enough forward production to pay for the costs of completing and operating the well and return a reasonable profit. Will not pay for the sunk costs.
- Commercial success, defined as reserves and production rates greater than the minimum economic threshold. This will vary with economic and political changes, such as changing prices, reduction in costs due to evolving infrastructure, new technology etc. Thus a geological, but non-commercial success may one day prove to be economic. In the North Sea in 1985, 200 bcf of gas was considered to be the minimum commercial size – by 1993 it had been reduced to 20 bcf in satellites to established fields!

## Risk and uncertainty evaluations

In the geological analysis, the primary risks and uncertainties involve the presence of a working petroleum system and the range of reserves sizes associated with an individual prospect. The commercial analysis is concerned with the ability to exploit the resources at economic rates, and to produce sufficient reserves at those rates to justify the capital and operational expenditures required to produce a reward consistent with the company's financial requirements.

Earlier, the concept of geological success was defined, and it is a key factor in the economic equation. In exploratory

drilling ventures, a risk of 10% chance of success would be typical for a rank wildcat well. In known, proven petroleum systems, such as the Rotliegendes gas reservoirs of the Southern North Sea, rates of success of 35-45% can be achieved. Higher estimates than this should be looked at with extreme care, and rejected completely in frontier exploration.

Binomial probability analysis can be applied to chance of success to estimate the chance of creating value from an exploration programme. It should be noted that this technique implies that opportunities share the same risk attributes and the "pot" can be replenished with similar prospects. As can be seen in Figure 1, that with high risk prospects with a 10% chance of success, on a statistical basis *at least* 15 wells would be needed to have an 80% chance of getting one discovery. For a 30% chance of success, at least 5 would be required. Of course, drilling 15 or 5 may still lead to no discovery, as anyone who has had any experience of a casino will well know!

Assuming that there is a consensus on the chance of geological success, the next requirement is to estimate the chance of commercial success. This is quite critical as, for example, two prospects of a similar play type may be so geographically positioned with respect to infrastructure, that one has a higher minimum reserves and production threshold than the other. For this reason, the non-commercial portion of the potential reserves distribution should be discounted.

## Lognormal distributions

Over the last twenty years it has been recognised by many workers in the field of exploration risk assessments that the most appropriate way of presenting the uncertainty of potential reserves distributions is through the use of the lognormal distribution, with an increase in variance between high and low estimates as geological uncertainty increases. There is a wealth of literature on this subject, and the reader is referred to Capen (1992), Megill (1992) and Rose (1999) for a thorough analysis of the issues. When a single value, representative of all potential reserves sizes is required, the most useful measure is the mean, in this case the statistical mean of the distribution curve. The formula for this is:

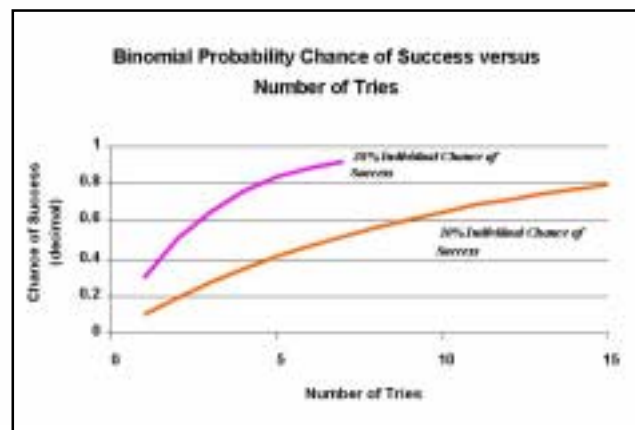


Figure 1: Probability of at least one success for individual chances of success at the 10% and 30% level.

$$M = e^{\mu + \sigma^2/2}$$

Where:  $\mu = (\ln P_{10} \text{ value} + \ln P_{90} \text{ value})/2$  and

$$\sigma = (\ln P_{10} \text{ value} - \ln P_{90} \text{ value}) / 2.56$$

Where variance is low, an approximate mean can be quickly calculated using a methodology developed by Swanson (e.g. Megill, 1996). This mean is calculated by summing values equal to 30% of the  $P_{10}$  value, 40% of the  $P_{50}$  value, and 30% of the  $P_{90}$  value.

The mean is strongly influenced by the potential upside values in the distribution, and where large variance exists it is often desirable to truncate the extreme end of the distribution, to eliminate reserves that are virtually impossible in nature. Truncation at the 1% probability level is recommended here. To determine the mean of the distribution of the *commercial* reserves, a further, lower, truncation is required which is taken at that probability which coincides with the minimum commercial field size. This then produces a doubly truncated distribution that requires a new commercial mean reserves value. Mathematical formulae have been developed to calculate the truncated mean, and the new truncated variance. These are somewhat involved procedures for which computer-based spreadsheets are ideally suited.

As a result of this operation a new commercial mean value has been created, which, being based on those reserves above the commercial threshold, is larger than the entire range mean. However, by removing the non-commercial portion of the reserves, the chance of commercial success is reduced. As an example, if the chance of geological success was 30%, and 40% of the reserves distribution was non-commercial, the new chance of commercial success is given by:

$$\begin{aligned} \text{Probability of commercial success (POCS)} &= P \text{ geological} \\ &\times (1 - F \text{ minimum size}) \\ &= 0.3 \times (1 - 0.4) \\ &= .18, \text{ or } 18\% \end{aligned}$$

The concepts of commercial versus geological success and the probabilistic distribution of reserves sizes are shown in Figure 2.

Having chosen values for the probability of commercial success, and a probability distribution for potential reserves, it is now possible to calculate a risk-based net present value for the opportunity.

## Risk and uncertainty weighted economics

The key issue here is to utilise the range of uncertainty in reserves predictions, and the chance of success, to calculate those economic parameters that are required for investment decision making. These vary within the industry, but such criteria as payback time, maximum negative net cash flow, discounted return on investment, profitability index and internal rate of return are usually prominent in any portfolio

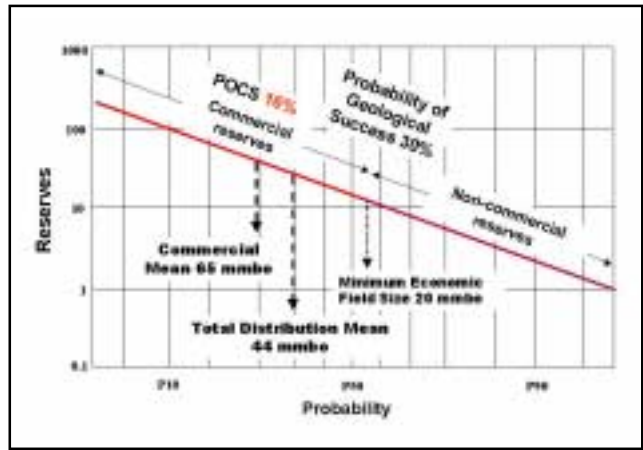


Figure 2: Probability distribution for non-commercial and commercial reserves.

listing. A fundamental measure, which is ubiquitously calculated, however, is the expected (risked) net present value (ENPV). There are two methodologies commonly used: the Decision Tree, and for multiple complex portfolio analysis, the Monte Carlo simulation. A decision tree will give a simple, easily understood picture of the calculation of the expected net present value based on chance of success and a range of potential reserves sizes and their associated rewards. For a single prospect, a Monte Carlo simulation is overkill. Figure 3 illustrates the concept for an exploratory well.

A point to note here is that the mean of the NPVs should be used, not the mean of the reserves distribution. The reason for this is that in the original  $P_{90}$  case in the example shown, producing those reserves would lead to a loss. It is apparent that in most prospects the NPV/boe will vary as economies of scale are realised. Truncation of the non-commercial reserves has been performed to calculate a mean NPV of the commercial reserves distribution. The chance of commercial success, rather than the higher chance of geological success, and the chance and cost of failure, is then used to create the risk-weighted net present value. ENPV can be used as a ranking tool as it compares projects having a similar rate of return but different reserves sizes, and particularly can compare high risk/high reward prospects with low risk/low reward ones. Its biggest drawback however is the fact that it

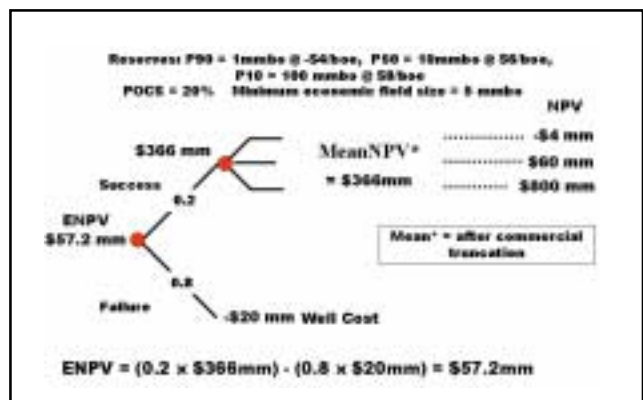


Figure 3: A D-Tree evaluation, illustrating non-commercial reserves truncation effect on Mean NPV.

is essentially risk-neutral, in that two prospects may have identical ENPV's but initial capital costs may be vastly different, such that one could put a serious strain on a company's cash flow.

## Diversification

There have been attempts by some companies to minimise risk by the concept of "cherry picking". This usually takes the form of some arbitrary edict such as "we only drill wells if our geologists think there is a greater than 25% chance of success" Apart from the obvious temptations of manipulation that must be present in any such organization, the company fails to recognise a simple statistical truth. For example consider two prospects with identical ENPVs and costs of failure, one having a moderate chance of success of 25% and the other a high risk one with a 10% chance of success, and a much larger NPV. The "cherry-picker" would drill only the lower risk prospect. If a company's budget only allowed the drilling of one opportunity, the temptation for many would be to drill the lower risk one at 100% equity. However, given that these are independent prospects, the overall chance of failure of drilling both prospects is given thus:

Prospect 1	Prospect 2	Probability
Success	Success	.25 x .1 = .025
Success	Failure	.25 x .9 = .225
Failure	Success	.75 x .1 = .075
Failure	Failure	.75 x .9 = .675

The chance of both failing is 67.5%, or more pertinently the chance of at least one success is now 32.5%, a significant increase from the 25% based on drilling the single moderate risk prospect. In addition, if each well is drilled at, say, 50% equity, the ENPV for the combined projects will be the same as for the single one. However, drilling both not only statistically reduces risk, but allows the participant at least a chance of realising the much larger NPV of the higher risk prospect. It must be remembered, however, that diversification for its own sake, without quality control, is not a good strategy.

## Sensitivities

The ENPV of a project is calculated from a variety of economic input parameters, which can be modelled in terms of their sensitivity. Each parameter in, say, a Monte Carlo simulation can be fixed (spiked) or can be selected from a distribution. A common sensitivity analysis is the Tornado plot, which demonstrates the effect that the variance of the parameter has on the range of potential outcomes. Figure 4 shows a Tornado plot for two onshore prospects, one oil and one gas, with two similar ENPVs. It is clear from this that reserves sizes have by far the biggest impact on uncertainty in the outcomes. The plots show that a focus on internal discount rate, oil price, operational costs etc., although a necessary part of the business, is worthless if the front-end reserves predictions are unreasonable. Analysis techniques assume quality technical input.

## Reality checks

It is not uncommon to see statements in the Press or farm out promotional material with claims such as "The Whoppa Prospect could contain reserves up to 1 billion barrels of oil (or 6 trillion cubic feet of gas, or whatever)". As an investor, one should consider:

- Big obvious structures are found earliest. Why has this one not been drilled before?
- If the answer is the subtlety, is this reflected in the chance of commercial success?
- How *small* could it be?
- Is there a validated analogue and what are the reserves ranges of the analogue fields?
- Has all the promotional data been examined, not just that which supports the case?

Figure 5 shows a plot of field size distribution against probability. Two other distributions are plotted. One is a high risk prospect with a large variance between the P<sub>10</sub> and P<sub>90</sub> exceedance probability values, the other, a low risk prospect with a much smaller reserves range. Note that the P<sub>50</sub> value is the same for not only the two prospects, but also for the field size distribution. It has been plotted this way to emphasise that the P<sub>50</sub> value, often referred to as a "base case", is a dangerous single value to use, in that it does not capture



Figure 4: Tornado plot sensitivity diagram showing overwhelming effect of reserves uncertainty.

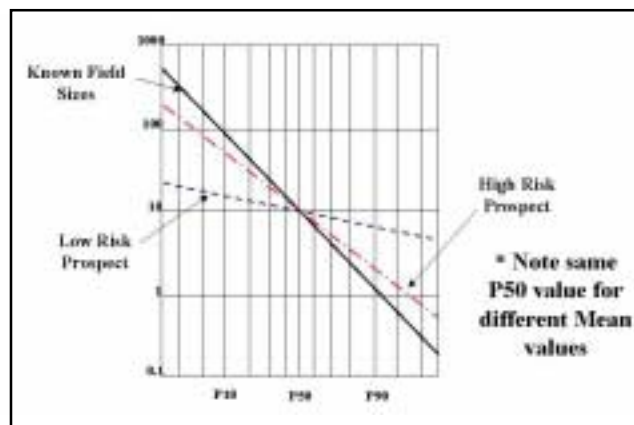


Figure 5: Prospect reality checks and reserves variance.

the variance, as does the use of the mean value. In the case of the “Whoppa” prospect, it is likely that the “could contain reserves up to” reflects the  $P_{10}$  case. At a 10% chance of technical success, there is only a 1% probability of finding these reserves. *Caveat emptor.*

## Optimum working interest

Having established that a prospect opportunity has a positive ENPV and other supporting economic criteria are favourable, the next major issue is determining the size of the desirable equity. Many companies do not always satisfactorily address this process. In licensing rounds, joint venture partners usually take an initial equity interest for the bidding procedure. After licence award, they may elect to maintain this equity for all prospects. It makes the operation of the joint venture simpler, and is certainly less demanding on time and effort. It does assume, nevertheless, that each equity holder has an identical response to each prospect’s risk/reward profile in terms of ENPV. That is, if using only ENPV as a ranking criterion, such factors as risk of loss, or size of potential reward are immaterial to the company. This is clearly not the case, as what is tolerable to, for example, Exxon in terms of the risk of a dry hole loss, is not as comfortable to a small struggling independent, for whom a \$20mm dry hole may mean the final curtain.

The ENPV can be adjusted downwards to take into account a company’s attitude to the trade-off between risk and reward. This is known as the corporate utility function (or risk tolerance, or risk preference). Cozzolino (1977,1981) introduced the concept of a risk-adjusted ENPV value to take into account these trade-offs. The methodology has been applied by many other analysts, such as Walls (1995). Essentially this methodology, which takes into account NPV, cost of failure, probability of success and a calculated risk aversion value (RAV), discounts the ENPV to a level whereby at a certain value of risk aversion, the company “feels” that the ENPV is negative. An example of risk-adjusted values based on an ENPV of \$1.75mm is shown as Figure 6.

The risk aversion value is calculated from the corporate utility function and attitude to total loss, although there are some “quick and dirty” approaches available when the utility is difficult to ascertain. Calculation of corporate utility may be becoming much harder to achieve, as increasing mobility of management and staff through restructurings, mergers etc., may lead to an entire change in a company’s attitude to risk over a very short period of time.

The optimum equity level can be calculated and is displayed graphically in Figure 7. For this particular prospect, the plot shows that an optimum equity level is 21%, although equity up to about 50% would be acceptable.

## Farm-ins and farm-outs

Farm-ins and farm-outs provide a useful vehicle for achieving optimum working interests and diversification. They take place for many reasons, financial and strategic, but all should be

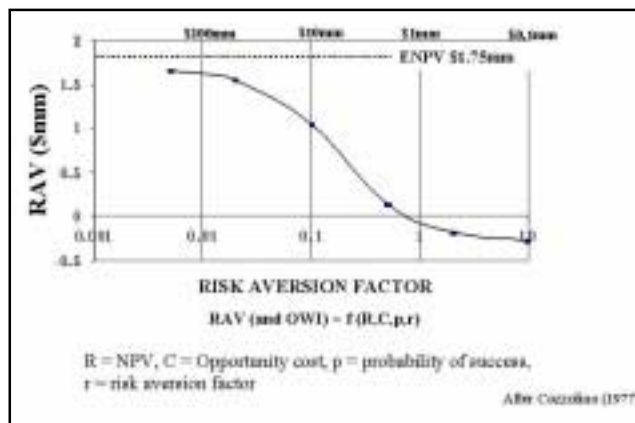


Figure 6: Risk-adjusted ENPV values using corporate risk tolerance criteria.

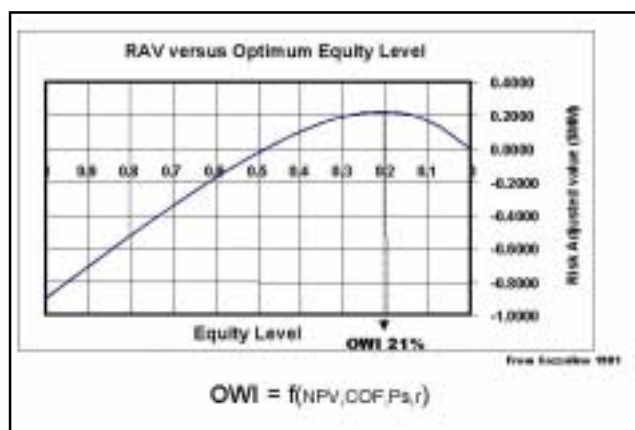


Figure 7: Optimum working interest determined from RAV values.

evaluated using, at the very least, the techniques listed above. In purely NPV terms, it can be demonstrated that there is a value equivalence that can be calculated, and which is a function of reward, cost of failure, probability of success and current equity level. In a farm-in/farm-out situation, the farm-out party is always attempting to farm-out an equity share less than the value equivalence, whilst the farm-in company is trying to do exactly the opposite. They thus have conflicting needs (Towler, 1989). Why then do they occur? Higgins (1990) lists three major reasons: to finance heavy expenditure commitments; to manage the portfolio; and to benefit from different perspectives of risk and reward. It is this last point that is emphasised by Towler (1989), who considers that the different perception of risk and reward is the reason why most deals are consummated. In purely ENPV terms, value equivalence is a neutral position for both companies, but is a benchmark for negotiation. Each company, however, because of their economic and probability assessments, will have different value equivalences. Hence at the end of the day, in the event of a discovery, and purely in NPV terms, one party will have gained at the expense of the other. In the event of a dry hole, the farm-out party has avoided all or part of the cost of failure. Figure 8 demonstrates these concepts in graphical form. Once again, these economic evaluations assume quality technical input.

## Peer review processes

Tversky and Kahneman (1974) have demonstrated the biases affecting judgment under uncertainty. This has obvious

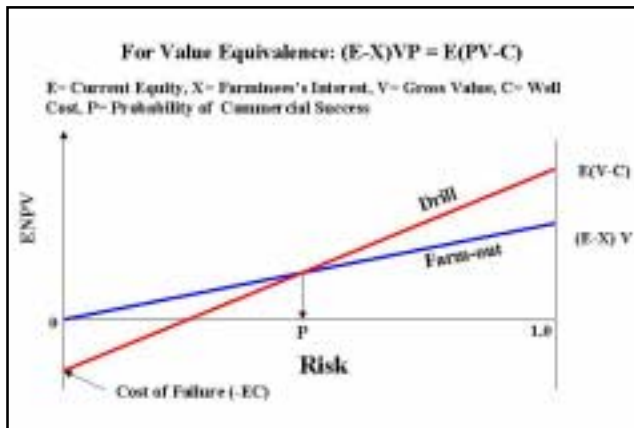


Figure 8: Graphical solution of equivalent risk value for farm-in/farm-out economic analysis.

implications for exploration prospect generation and decision-making processes. Rose (1999) lists seven major types:

- Overconfidence: estimators are less accurate than they believe they are.
- Representativeness: analogues are not truly representative or statistically too small to have confidence in.
- Availability: use of spectacular or recent examples, regardless of natural chance of occurrence.
- Anchoring: limiting upside and downside estimates too strongly.
- Unrecognised limits: considering only geological factors in the predictions.
- Motivational: a real problem in these days of downsizing. Selling deals for personal career prospects. Often works because of “shared committee culture” and political ability to avoid consequences.
- Conservatism: “Management loves it if it turns out to be bigger than predicted”. Again, a career-prospect motivational bias.

Biasing can be reduced by the use of multiple working hypotheses. All prospects are based on very incomplete geological and geophysical information. Alternative interpretations should always be built into the risk process. The use of proper statistical techniques, and the recognition of the fact that lognormal distributions are inherent in natural populations, avoids the “Whoppa” effect. Reality checks and genuine analogues also impose constraints on the upside and downside values of reserves, and the chance of success. Independent peer reviews performed by third parties are an invaluable technique to minimise the subtle individual agendas present in any committee review. Finally, a robust post-appraisal process ensures that the organization learns from its activities and continually updates its concepts of risk and reward.

## Conclusions and implications for exploration in New Zealand

A systematic approach to risk and reward should be a prerequisite for all companies engaged in the high-risk business

of upstream investment. Despite secret hopes of some managers, “cherry-picking” to reduce risk is a flawed methodology. It has to be assumed that technical talent is reasonably spread throughout the industry, and if just having clever people held the key, there would presumably be highly paid prospect-generating “superstars”. This author has yet to meet one, unless they have made a fortune as an independent. Intelligent diversification increases the overall chance of success, even if high-risk prospects are included. These must be present in any portfolio, as it is this class of prospects that generates the “Company Makers”. Geological estimates of risk and reward are often overly optimistic and do not acknowledge that the range of potential outcomes could be much wider than those presented. Independent peer reviews present an opportunity to minimise organisational bias and hidden agendas. Portfolio management is a demanding process that requires continual tuning. Optimum working interests maximise the available budget’s ability to avoid loss, and satisfy the risk tolerance of the company.

In New Zealand, it is clear that drilling activity is not (and has not been) sufficient to “play the odds” in many play fairway trends. Working interests are probably not optimal for many companies. Whether this is by necessity (inability to farm down or access the right equity) or by choice (trying to keep a high interest in the “best” prospects) is unclear. The relative isolation of the country must be a contributing factor, as it is noticeable that New Zealand tends to appear then disappear with fluctuating oil prices on corporate “radar screens”. This suggests that all those involved in the industry must apply extra effort in order to maximise the value, not only of their own portfolios, but also of Portfolio New Zealand.

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