A consistent due diligence methodology for prospect evaluation and investment decisions: getting the "best bang for your buck"

SJ O'Connor and S Courteney

GeoProfessionals Ltd, P.O. Box 903, Masterton 5901, New Zealand. Ph +64-6-370-8639 Email office@geoprofessionals.com

Abstract

The operational costs of acting on exploration data evaluations are often an order of magnitude greater than the costs of the data acquisition, which are in turn commonly an order of magnitude greater than the costs of data interpretation. It would seem prudent, therefore, to ensure that appropriate due diligence is applied at the low cost interpretational level, as this is the fundamental underpinning of the future higher cost decisions and actions. Nevertheless, this is very often not the case.

For explorers, a consistent methodology not only provides a framework for internal decision-making, but also increases the level of credibility for investors. For investors, particularly those with limited geotechnical resources or those unfamiliar with petroleum system risk analysis, failure to appreciate the concepts of exploration uncertainties, risks and rewards may lead to poor investment decisions. Disappointments may then lead to disenchantment with the prospective area, or basin, and even exploration investment in general.

A due diligence methodology is presented which applies a consistent and rigorous approach to each opportunity. This approach can also be applied to the portfolio level and evaluated in terms of a company's particular risk tolerance. Optimum equity levels can be determined for each prospect depending on the overall investment budget available.

Examples from independent technical and economic evaluations of prospects in New Zealand are presented that demonstrate some of the issues, inconsistencies and pitfalls involved when evaluating exploration opportunities.

Introduction

The beginning of the new millennium has seen a major change in the perception of the security of New Zealand's energy supply. The cornucopia of gas supplies from the giant Maui Field is rapidly coming to an end, without a significant replacement on the horizon. Recent reserves downgrades at Maui Field have brought the issue sharply into focus. The period has also seen a major change of ownership of the rights to explore and develop new gas reserves. The farm-in by Shell and Todd to the Pohokura well in 2000 fundamentally changed the future of the New Zealand petroleum industry. Success at Pohokura led to the takeover of Fletcher Challenge Energy, New Zealand's largest independent exploration and production company, by Shell.

Given this huge change in the dynamics of the gas market, energy companies and other stakeholders are asking three basic questions:

1. How much proven and probable gas is there?
2. How much more can one expect to find in the next few years?
3. How much will it cost to develop and sell?

A new phenomenon, however, has emerged in recent years, that of the downstream participant in exploration funding in order to ensure future options on gas supplies. The most notable of these is Genesis Energy, which has taken a stake in Kupe Field, but does not wish to operate. Orion Energy has also participated in frontier exploration with the Westech Joint Venture on the East Coast.

In the past year smaller exploration companies have apparently acquired direct exploration funding capital from potential gas purchasers. This is a different situation from the normal farm-in/farm-out business that takes place in the upstream industry, where investors tend to be other exploration companies or, in the case of exploration "minnows", private sleeping partners. The sums that are being asked of these new entrants are, in some cases, considerable and equivalent to the costs typically associated with regular farm-ins, but without allowing the funding organisation full representation in the Joint Venture. Because of this, it is important for these new entrants to understand the ways in which exploration prospects are created and monetised. A due diligence process to achieve this is presented below and summarised as Figure 1.

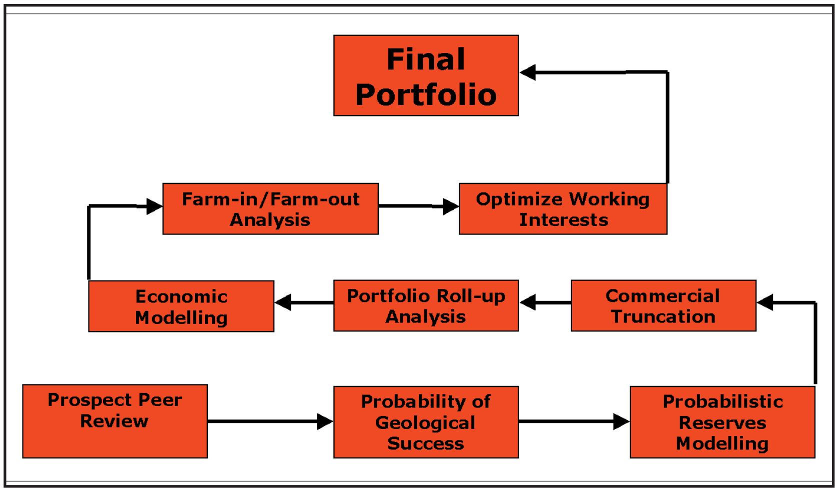


Figure 1. Due Diligence Model

Peer reviews

Based on the above discussion, it is therefore worth considering the nature of the oil and gas exploration and development industry not only just in terms of the technical and financial data, but also the way in which such data are subsequently interpreted and used to make extremely costly business decisions. In other words, an understanding of the way in which data are gathered, compiled, interpreted and presented is vital if one wishes to truly understand the risks, uncertainties and rewards associated with the industry.

As Tversky and Kahneman (1974), for example, have demonstrated, bias has a major role in affecting judgment under uncertainty. This has obvious 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: Selling deals for personal career prospects.
– Conservatism: "Management loves it if it turns out to be bigger than predicted".

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, attempts to capture the diversity that is frequently masked by biasing. 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 internal committee review. A robust post-appraisal process ensures that the organization learns from its activities and continually updates its concepts of risk and reward. Finally, the use of standard due diligence procedures and associated templates provides a consistent approach to investment decisions, captures all relevant information for use in future post-appraisals and creates consistency when managing portfolios. GeoProfessionals Ltd uses such templates wherever possible in any independent review process.

Fairway analysis

Fairway choice is one of the most important decisions explorers can make, as early entry into the most productive fairways will greatly increase not only chance of success, but also potentially lock up the most prospective structures. 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. Fairway analysis is a time-consuming exercise. It requires an inter-disciplinary exercise involving geologists, geophysicists and reservoirs engineers, together with associated specialists in geochemistry and fluid dynamics.

In New Zealand, over 85% of reserves discovered to date are in the Kapuni Group. Although there is still much to learn about the Kapuni Group and oil and gas migration in general in New Zealand, it is obvious that a key reason for the distribution is that the source-rock and reservoir are stratigraphically coupled.

A due diligence process, particularly outside the proven fairway trends, would normally investigate the seller's knowledge of the fairway systems in the area, rather than just focussing on the prospect, as it may well be that the particular opportunity is not of a proven play type.

Probability of 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.

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:

Psource x Pmigration x Preservoir x Pseal x Ptrap = Probability of Geological Success.

Reserves distributions and commercial truncation

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. 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 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. 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. 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:

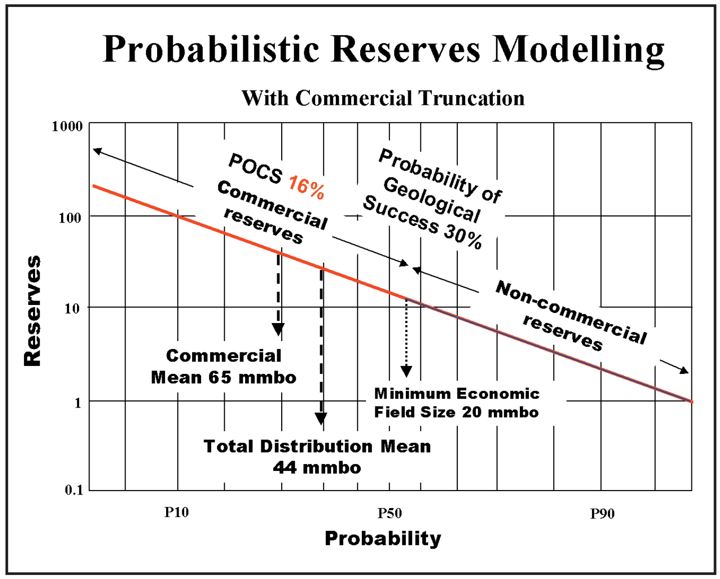


Figure 2. Probabilistic Reserves Modelling with Commercial Truncation

Probability of commercial success (POCS)

= P geological x (1- F minimum size)

= 0.3 x (1 - 0.4)

= 0.18, or 18%

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

Economics

Economic analysis may be presented as part of the opportunity-offer documentation. It is extremely unusual, however, for investors not to perform their own economic analysis. One of the major issues (apart from the understanding of the geotechnical risks and the potential reserves distribution) is the input to the economics. Whilst there may be some disagreement with input values for Capex and Opex, most data are fairly well constrained. Obviously, use of the highest oil price in the last 10 years as a standard, for example, is not to be recommended.

One of the major issues for the analysis is the discount rate used. Bearing in mind the cost of capital in today's environment, the use of very high discount rates (>20%) penalises long- term projects. The question is, why use this value, when the current cost of capital is closer to 8%? The answer is likely to be a case of "double-dipping" on risk, where it has been decided that the risks predicted by the technical personnel are over-optimistic and should somehow be scaled back by prudent economists. It works in some ways, because the riskier projects are often not drilled and so one never knows how well the technical people would have done. However, the main issue is that the use of over-inflated discount rates represents distrust in one's staff, or over-conservatism, as many of these projects have the potential to be "company-makers". It would be far better to develop techniques geared to improving the ability to predict and manage risk and rewards, rather than using flawed logic. A consistent due diligence process goes a long way in delivering this.

Farm-in / Farm-out analysis

Farm-ins and farm-outs provide a vehicle for achieving optimum working interests and diversification. They take place for many reasons, financial and strategic, but all should be 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. 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 3 demonstrates these concepts.

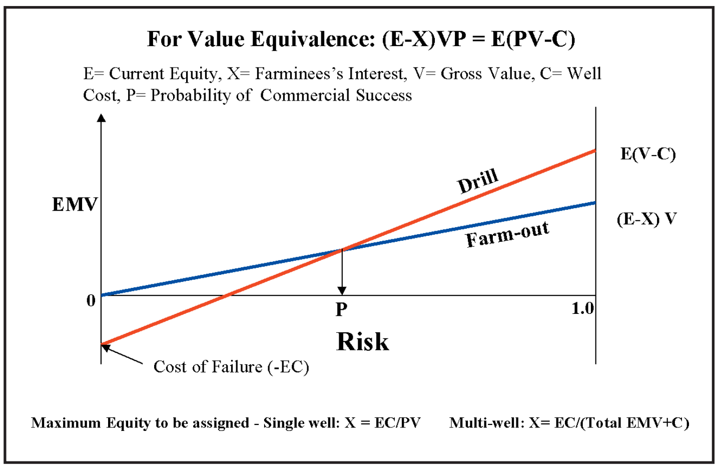


Figure 3. Farm-in/Farm-out Analysis

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, ExxonMobil 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 (Cozzolino, 1977). This is known as the corporate utility function (or risk tolerance, or risk preference). 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. Multiple-prospect portfolios can be analysed, each prospect having its own risks and rewards. These can then be rolled-up to calculate the optimum equity, bearing in mind those risks and rewards and the company's tolerance to loss. A modification of the technique can be applied where the optimum working interests can be calculated if a fixed budget is applied. An example is shown as Table 1.

Portfolio analysis

The mean for each prospect is compounded and the Portfolio Mean, M*, calculated for the mixed distribution, where the * indicates the condition of at least one discovery (see for example Capen,1992). In true portfolio analysis, each lead or prospect would be given an individual chance of success, which is used in the calculation of M*. The portfolio distribution approach is one that combines individual means and variances for each of the prospects. These are the mean and variance of a binomial lognormal distribution. A mean value, M*, is calculated that represents the average of all that can happen in terms of the combined distributions. The chance of success reflects multiple trials and indicates that chance should all the prospects be drilled. Chance of success can be input as geological success or commercially truncated

OPTIMUM WORKING INTEREST

PROSPECT	NPV	Cost	POS	RT	Equity	r	100% RAV	ENPV	EV@OWI	OWI	OWI COST
ALPHA	0.5	0.1	0.2	1	1	1	-0.005	0.02	0.0074	0.37	0.037
BETA	2	0.5	0.25	1	1	1	-0.239	0.125	0.0144	0.12	0.058
GAMMA	0.7	0.1	0.15	1	1	1	-0.014	0.02	0.0053	0.26	0.026
DELTA	0.005	0.001	0.8	1	1	1	0.004	0.0038	0.0038	1.00	0.001
EPSILON	0.14	0.1255	0.5	1	1	1	-0.002	0.00725	0.0030	0.41	0.052
								0.17605	0.0339		0.174

Table 1. Optimum Working Interest

as desired (O'Connor, 2000). An example is shown below as Figure 4. In this case all prospects share a common risk for simplicity, to clearly demonstrate the fact that M* and C* do not relate to any individual prospects.

Final Portfolio

Prospect	Mean	Variance	POGS(p)
325-H	537	1.780	0.26
325-K	162	0.964	0.26
325-L	368	1.508	0.26
326-A	210	1.146	0.26
326-G	265	1.304	0.26
326-H	331	1.433	0.26
326-I	216	1.159	0.26
326-L	575	1.823	0.26
333-H	301	1.397	0.26
333-O	152	0.956	0.26
333-R	214	1.150	0.26
Portfolio Mean Reserves*	899		
Geological Chance*	0.96		
Portfolio P50*	531		
Portfolio P10*	1975		
Portfolio P90*	143		

Figure 4. Portfolio Analysis – Final Portfolio Roll-up

Benchmarking

An important, and often ignored aspect of probability distributions of field and prospect sizes is that practicality and economics often dictates the size range of fields and prospects. It is well documented through numerous observations and studies, that Nature has provided a series of structural closures, and indeed hydrocarbon accumulations that generally follow a lognormal cumulative probability distribution. That is, there are many more small fields and structures than very large ones. Acceptance of this principle provides a powerful predictive tool for potential reserves distributions. It also poses problems in that if only the larger closures are identified and assumed to be full to spill point, the calculation of mean reserves will be overly optimistic. In addition, even very large structures may, for geological reasons, contain only very small reserves. The ability to predict hydrocarbon reserves, based on structural closure, is much reduced in frontier areas as opposed to mature areas. Even in mature areas, however, one must accept that there is always a chance of finding a very small accumulation in a large structure. Thus, in probability modelling, the variance of the reserves distribution should reflect the uncertainties that exist. Frontier basin prospects should therefore have larger variances on pre-drill predictions than those in mature areas.

An investor 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 relevant data been examined, not just that promotional material which supports the case?

In more mature areas, a cumulative field size distribution plot can be created that can be used as a guide to risk versus reserves. This can be attempted (albeit with many reservations) for the Taranaki Basin, but not for elsewhere in New Zealand.

Over two decades ago most exploration and production companies had sufficient resources to employ specialist basin evaluation teams that operated on a world-wide basis. Consequently, in such cases as the presently unproductive basins of New Zealand, overseas analogues and experience would be applied to the benchmarking exercise and subsequent exploration activity. Some key papers from this period are Bally and Snelson (1980), Klemme (1980) and Kingston et al (1983a and b). Though many explorers in New Zealand cannot afford the luxury of such teams, it is still possible to tap into such a wealth of experience.

Examples are presented below of some simple benchmarking exercises that have arisen from due diligence investigations. Sometimes the failure of a prospect to meet a simple benchmark is sufficient to raise alarm bells.

Example: relative prospectivity of unproductive New Zealand basins

While the presently unproductive basins of New Zealand can be considered to be relatively under explored, sufficient is known about these basins to be able to compare them with basins overseas and to make inferences on the potential plays within these basins that will potentially be successful. The most significant aspect of New Zealand petroleum geology is the close proximity of all basins in New Zealand to the active margin between the Pacific and Australian plates. While some workers will argue with justification that this situation is unique, it is not the only example in the world of an active plate margin between oceanic and continental plates. From the view of the petroleum geologist the most prolific similar margin is that between the Eurasian and Indian-Australian, which stretches for some 6,500 km through the Southeast Asia. This is over three times the length of the margin through New Zealand. Table 2 shows a reservoir correlation between 18 basins on the Western Indonesia segment (~3,600 km) of the Eurasian/Indian-Australian margin (Courteney, 1995).

It is useful in that it demonstrates that even after over a century of exploration prolific surface seeps and even shows in wells do not necessarily lead to commercial hydrocarbon production. Consequently, with modern exploration, surface seeps are not considered an adequate benchmark for the existence of a commercially exploitable petroleum system. If anything the fact that the seeps have reached the surface could be taken as an indicator that no effective traps exist in the sub-surface!

Though the Paleogene source rocks are not shown on Table 2 the production from the Middle Miocene and younger reservoirs is due to the absence, or failure, of the regional seals. Consequently, this table also illustrates the key lesson learnt in the Taranaki Basin namely that the larger fields

	Sibolga	North Sumatra	Central Sumatra	South Sumatra	Sunda	Bengkulu	N.W. Java	C. Java - Pati	E. Java	South Java	Northeast Java	Lombok	S. Lombok	Barito	Melawi	Ketunga	E. Natuna	W. Natuna	Percentage Reserves Selected W. Indonesian Basins (MMBOE)	Percentage Reserves NZ (Taranaki - MMBOE)	Cumulative Central & Northern North Sea Production (12/98)
Basin Fully Offshore?					Yes							Yes	Yes	Yes			Yes	Yes			
Pleistocene		↑		↑		↑	↑	↑	↑	↑				↑					0.08	0.00	0.00
Late Pliocene	↑	↑		↑		↑			↑	↑									0.88	0.03	0.00
Early Pliocene		↑		↑					↑												0.00
Late Miocene		↑		↑				Sh	↑	↑									18.61	1.15	0.00
Middle Miocene																			8.51	1.81	0.00
Early Miocene						Sh													47.48	2.18	0.00
Late Oligocene																			16.51	2.88	0.00
Early Oligocene															↑				6.76		
Late Eocene						Sh									↑	?↑?				85.68	
Middle Eocene																			0.73	0.00	1.00
Early Eocene																			0.10	1.90	
Palaeocene																				4.37	12.00
Pre-Tertiary																			0.34	0.00	87.00
Basin Size (km2)	50,000	64,000	96,000	82,000	15,500	99,000	31,000	45,500	38,500	52,500	90,000	40,000	29,000	22,000	25,000	15,000	60,500	63,000	918,500	85,000	246,500
MMBOE	0	5,357	10,830	3,614	1,309	0	2,087	147	554	0	92	430	0	181	0	0	7,684	786	33,072	1,380	4,439
Benchmark	✓	✓✓	✓✓✓	✓✓	✓✓✓	✓	✓✓	✓	✓✓	✓	✓✓	✓✓	✓	✓✓		?✓?	✓	✓✓			

Legend

Commercial Production - North Sea & Taranaki

Commercial Production - Indonesia: Clastics

Commercial Production - Indonesia: Reef

Commercial Production - Indonesia: Volcanics

Commercial Production - Indonesia: Pre-Tertiary Metamorphic and Igneous Rock Units

Indonesia - Viable Reservoirs

Non-Commercial Fields (In Indonesia background colour indicates lithology)

Surface Seeps (Background colour indicates reservoir crops out at surface) ↑

Shows in Wells (Background colour indicates lithology) Sh

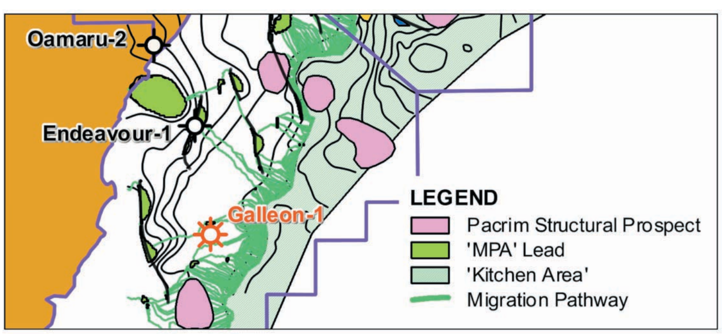
Indonesian Basins Benchmarked as follows:
- ✓ for no seeps
- ✓ for full post Middle Eocene somewhere in the basin
- ✓ for Oligo-Miocene clastic reservoirs below regional seal

Table 2. Reservoir Correlations: Selected Western Indonesia Basin, Taranaki Basin and North Sea.

occur where the source-rock and reservoirs are closely coupled. The North Sea column (Evans *et al*, 2003) illustrates the similar situation where hydrocarbons from Pre-Tertiary source rocks are unable to migrate to Neogene reservoirs.

Example: post-appraisal analysis testing for migration problems

Frequently, prospects are presented with little information on oil and gas migration paths. Sometimes this is not particularly significant, as the reservoir may be encased in source rocks. Other times, the migration pathway may be more tortuous (and risky). Figure 5, shows how a well in the Canterbury Basin (Galleon-1), with limited reserves (either due to under-filling or seal problems), may be located in a zone of partial migration shadow. An adjacent structure shows richer migration volumes. A presentation such as this may help to explain the lack of commercial success at Galleon and would be a positive for future exploration.



Testing of a prospect for hydrocarbon fill can be made using migration analysis. A first pass map on a regional scale suggests significant shadow zones are present.

Modelling will be required at the local prospect level.

Figure 5. Migration Pathways Analysis of the Canterbury Basin: Galleon-1 Well

It should be noted that the example of the Canterbury basin was relatively simple. In other New Zealand basins, which have undergone more deformation, it is often necessary to carry out palinspastic reconstructions as part of the migration pathways analysis.

Example: reserves benchmarking for multi-well farm-out offer

The following Table 3 is taken from published information that originally derived from a farm-out promotional brochure.

NZ PROSPECT INVENTORY

Prospect	Oil (mmbo)	Gas (bcf)	Total (mmboe)
G	252	356	311
T	55	109	73
P	205	410	273
C	145	1920	465
B	1000	10800	2800

Sources: Crown Minerals and data released by New Zealand E&P companies

Table 3. Prospect Listing

The reserves are described as "Best Case". What this meant is not clearly defined, but could relate to simple deterministic reserves, the P50 or the Mean. It is likely that it refers to the P50 as no indication is given anywhere of the use of lognormal distributions for predicted reserves.

Figure 6 is a cumulative probability plot for field size distribution in the Taranaki Basin. Plotted are the P50 predictions for the prospects. Issues that quickly arise are:

1. "Best Case" estimates are clearly very much higher than those found historically in the Taranaki Basin, a basin

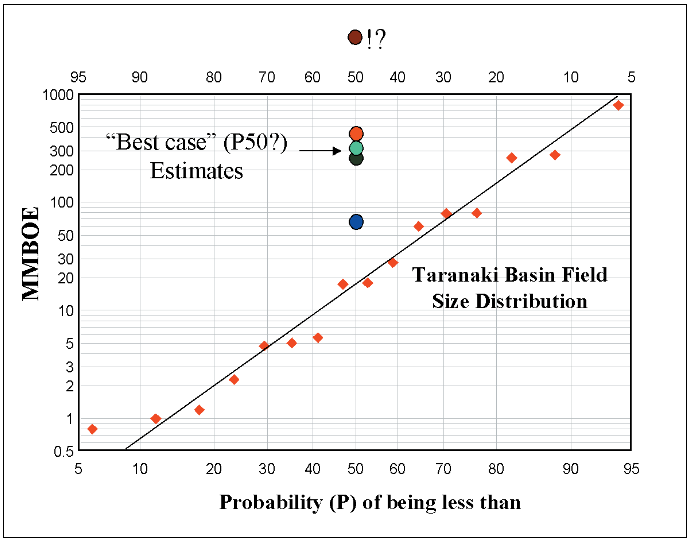


Figure 6. "Best Case" Reserves Canterbury Basin Farm-out Offer compared to Taranaki Basin Field Size Distribution

thought to be richer in hydrocarbons than the basin under investigation.

2. An offset structure in the same petroleum system has reserves of 7 mmboe. This was used as the P90 value, as this would equate to Proven Reserves under SEC/WEC rules
3. Even adjusting for this and using the "Best Case" value as the P10, the re-calculated P50 value is still uncomfortably high. Further investigation of input parameters into reserves calculations will be required.

Example: East Coast Basin prospect

When working in unproductive basins an assumption can be made, that there is generally a correlation, albeit a loose one, between areal size of closure and magnitude of reserves. Obviously, in the real world, factors such as seal capacity, shape and style of closure, height, porosity and recovery factors all display a large variance. In an attempt to provide some kind of reality check for New Zealand prospects, data was gathered from field size distributions versus area of closure from the Taranaki Basin and the North Sea. In Taranaki, data are sparse, and few, if any, companies will provide public information on reserves and structural closures. Data from the North Sea was selectively chosen to reflect "average" structural fields, rather than super-rich fields such as Forties with a 70% recovery factor.

For statistical analysis it is necessary to look at subsurface reservoir volumes as a function of size to remove the effect of gas expansion and oil shrinkage, and the large variation in recovery factor. In particular, it is felt that the often-utilised BOE approach, whereby 1 barrel of oil = 6 Mcf, is logically erroneous, in that this energy-related conversion does not relate to geological conditions. As an example, a barrel of oil in the subsurface may shrink to half its size at the surface i.e. a stock tank barrel represents 0.5 of a reservoir barrel. For gas, a reservoir at say 2000 feet may contain 1 billion cubic feet of compressed gas that expands to 100 Bcf at the surface. The same reservoir volume of gas at a much greater depth, or in a significantly overpressured reservoir at a moderate depth, may expand to 350 Bcf at the surface. For this and the previous reasons, all benchmarking has been carried out in reservoir volumes. For statistical reserves modelling, the reservoir volumes are converted back to conditions of surface temperature and pressure.

A prospect in the East Coast Basin of New Zealand has been touted as having deterministic reserves of approximately 4000 PJ (approximately equal to 4 Tcf of gas), which would make it somewhat comparable to Maui Field in reserves size. Bearing in mind earlier comments about how rich the Kapuni Group petroleum system was, because of the stratigraphically coupled nature of the source/reservoir pair, and the reasonable correlation between area and volumes, one would expect the size of the prospect to be reasonably comparable. Figure 7 below shows the reserves value plotted on the Taranaki/ North Sea graph. Thus for this East Coast prospect, reserves of 4 Tcf have been attributed to an area of 40 sq km. This would make it 3 times richer than Kapuni and Maui fields. The basin has yet to demonstrate reservoir quality comparable to the Maui Sands or the Rotliegendes Sandstone of the giant Indefatigable and Leman fields in the Southern North Sea.

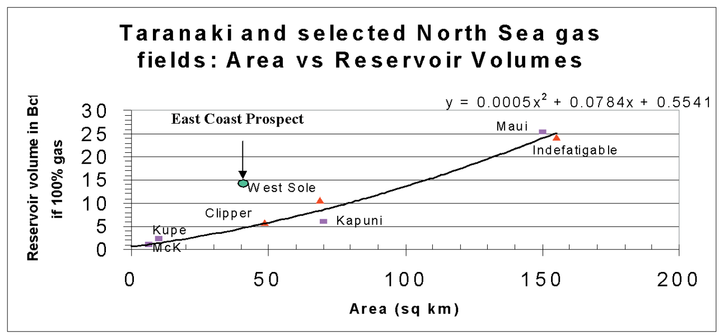


Figure 7. East Coast Prospect benchmarked against Taranaki and selected North Sea Gas Fields using area versus reservoir volumes

Example: field fill factors

It is a widely held misconception, or myth, that all fields are filled to their spill point. In fact it is extremely rare to find a medium to large sized field that is filled to the spill point. The degree of fill of a field, or prospect, is a function of several factors such as the richness of the source rock feeding the trap, the ability of the trap to halt the initial migration and the ability of the trap to maintain its structural integrity over time through subsequent structuration.

As mentioned earlier, New Zealand is located on an active plate margin with some 32 earthquake epicentres recorded with magnitudes greater than 5 and at depths up to ten kilometres in the last decade (GEONET, 2004). Clearly, traps in New Zealand are at risk of structural failure. Figure 8 puts this in perspective. Five Palaeogene fields from the North Sea are shown out of a total of 66 producing fields and two non-commercial fields as at 12/1998 (Evans *et al*, 2003). The North Sea is considered to be tectonically passive and as can be seen, even fields in passive zones are at best only 77% (Siri) to

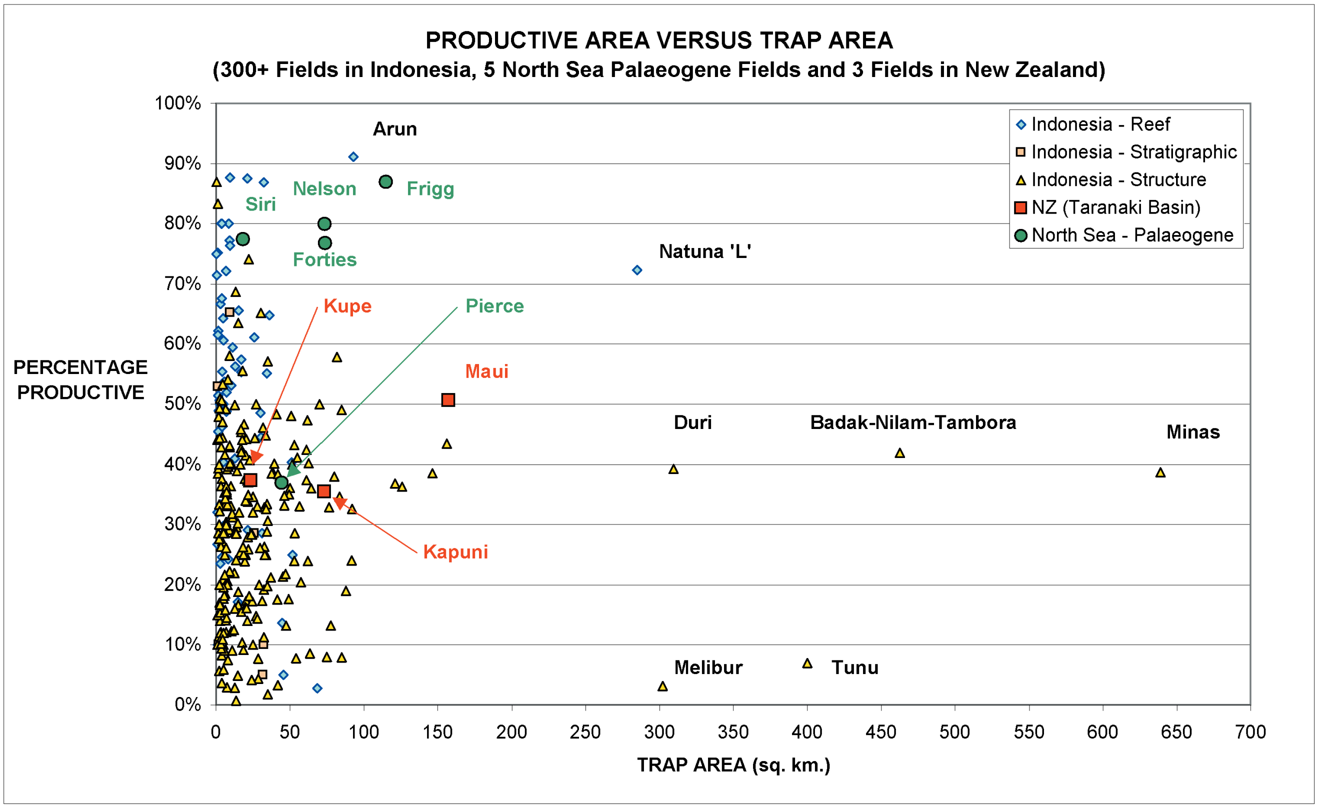


Figure 8. Productive Area Versus Trap Area: Tertiary Fields in North Sea, Indonesia and New Zealand

87% (Frigg) filled by area. These statistics are derived from Evans *et al* (2003), Hill and Wood (1980) and Heritier *et al* (1990) using maps prepared based on modern 3D seismic surveys, hydrocarbon contacts established during production, etc.). In contrast fields in Indonesia (Pertamina – Beicip, 1985, Courteney *et al*, 1988, 1989a, 1989b, 1990, 1991a and 1991b, Caughey *et al* 1994 and 1995) illustrate the problem with basins on active margins. Namely these basins are also tectonically active and hydrocarbon traps are being actively destroyed. Consequently, as can be seen from examples of over three hundred fields, fill factors by area greater than 50% are rare. These are predominately reefs such as Arun and Natuna 'L' where preservation of trap is easier for a shale encased reef than for interbedded sands and shales in structural traps. It is interesting to note that the only significant tectonic activity in the North Sea is salt diapirism and the Pierce field, which is

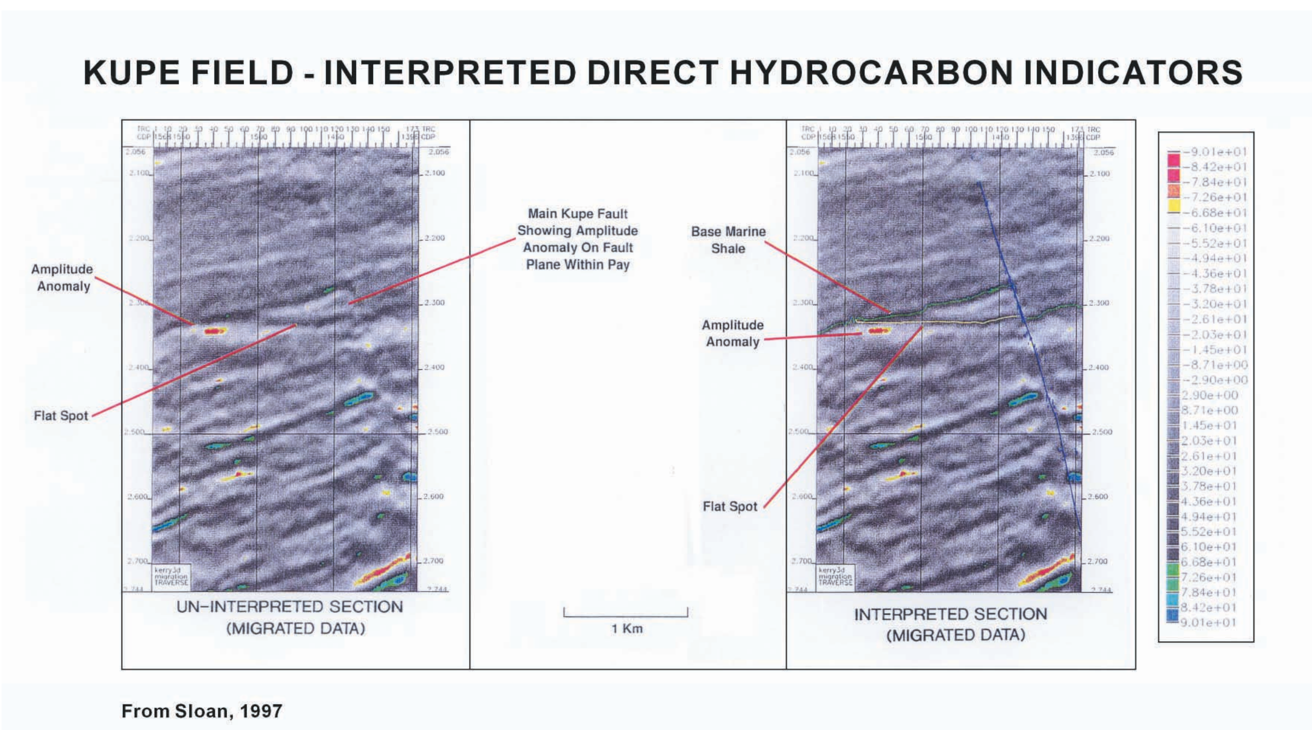


Figure 9. Kupe Field: Interpreted Direct Hydrocarbon Indicators

pierced by two salt diapirs, falls in the Indonesian "structural" cluster with a 37% fill by area.

Data on fields in New Zealand is harder to find, but using Sloan (1997), Abbott (1990a) and Farmer and Adams (1998) and Abbott (1990b) together with open file seismic data, structural and productive areas have been determined for respectively the Kupe, Maui and Kapuni fields. Perhaps not surprisingly, bearing in mind New Zealand's position on an active plate boundary these fields all fall within the Indonesian "structural" cluster.

As a footnote it should perhaps be mentioned that the Kupe structural closure covers the Kupe South wells and just extends to the Kupe –1 well. Some would argue that the structure is in fact much larger.

Example: direct hydrocarbon indicators (DHIs)

Direct Hydrocarbon Indicators are considered by many as the 'silver bullet' in oil and gas exploration - "The gas, or oil, is clearly visible on the seismic data so let's build the refinery. Oh, and do not forget to drill a few wells!"

Figure 9 shows two major types of DHI: amplitude anomalies and a flat spot from the Kupe field as interpreted by Sloan (1997) and as yet is neither verified nor disproved by subsequent drilling. Other DHIs such as phase change, amplitude variation with offset, amplitude variation with angle, etc. also exist. The key word with this Kupe example is "interpretation". While DHI's are called direct hydrocarbon indicators they are an *interpretation* of the complex interaction between the rock properties in the rock matrix and the fluid properties in the pore spaces as is imaged on seismic reflection data. For each DHI there are many non-unique solutions and a significant number of these do not entail commercial success and may also not include geological success. Engbers (2002) is an excellent example in New Zealand of DHIs from the Maui field. Engbers "learning points" are important benchmarks for anyone thinking of drilling on the basis of DHIs. These are:

- The Whaarangi "oil accumulation" case study shows that caution should be exercised, even when a series of very positive indications exist
- 1.5 litres of recovered oil do not necessarily prove an oil accumulation
- Always give enough weight to the possibility of good seismic Direct Hydrocarbon Indicators being related to a reservoir with only residual/non-mobile hydrocarbons

In this oil case Engbers (*op. cit.*) reported mid hydrocarbon saturations of 47%. It should be noted that in the case of gas reservoirs much lower saturations give good DHIs. Non-geological causes for amplitude anomalies include facies changes (e.g. sand with interbedded coal stringer) and flat spots can indicate palaeo-water tables.

Overseas experience has also shown that the application of DHIs is best suited to areas with a high well density and a well-known stratigraphy. Its application in rank frontier acreage has only met with limited success.

Conclusions

A consistent due diligence methodology adds value by:

- Producing a consistent framework for investment decisions
- Documenting, through standard enquiries and templates, all the necessary inputs into the technical and commercial evaluations of prospects
- Minimizing bias in project sellers
- Conducting post-appraisals to capture learning and provide a platform for continuous improvement monitoring
- Comparing the risks and rewards of investment opportunities using international benchmarking to provide reality checks

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Authors

STEVEN O'CONNOR is a Consultant Petroleum Geologist with GeoProfessionals Ltd and Governing Director of Diligenz Limited. He has 30 years international industry experience in North Africa, the Middle East, the North Sea, the USA and New Zealand. He graduated with a B.Sc. (Hons) in Geology from the University of Leicester in 1974, is a Chartered Geologist and Fellow of the Geological Society of London, and a Certified Petroleum Geologist.

STEVEN COURTENEY is Technical Director of GeoProfessionals Ltd and Director of Wairarapa Geological Services Limited. He has 27 years International industry experience in China, Europe, the Middle East, South America, Southeast Asia, the USA and New Zealand. He graduated with a B.Sc. (Hons) in Geology from the University of Wales in 1977, is a Chartered Geologist and Fellow of the Geological Society of London, member of the Indonesian Petroleum Association, active member of the Society of Exploration Geophysicists and a Certified Petroleum Geologist.