Quick Look Methods of Economic Exploration Portfolio Evaluations and its Exemplary Application on the Prospect Inventory

Diploma Thesis

by

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Abbreviations

AAGP	American Association of Petroleum Geologists
BCF	Billion Cubic Feet
BOE	Barrel Oil Equivalent
CAPEX	Capital Expenditures
CDF	Cumulative Distribution Function
d	Day
E&P	Exploration and Production
ECF	Economic Chance Factor
EMV	Expected Monetary Value
GCF	Geologic Chance Factor
MCFS	Minimum Commercial Field Size
MCOP	Minimum Commercial Oil Price
MES	Minimum Economic Size
MM	Million
NPV	Net Present Value
OPEX	Operational Expenditures
Pc	Commercial Chance of Success
PDF	Probability Density Function
Pe	Economic Chance of Success
Pg	Geological Chance of Success
PI	Prospect Inventory
PRM	Peter Rose Methodology
SA	Sensitivity Analysis
SPE	Society of Petroleum Engineers
USD	US-Dollar
VPB	Value per Barrel
VPD	Value per Dollar
WPC	World Petroleum Congress

1 Abstract

Every year oil companies have to invest larger sums for exploration projects as the remaining petroleum reserves are more and more located in environmentally difficult areas, like deep water or arctic locations. Therefore it is essential for these companies to make the right investment decisions in order to enhance the wealth of the company. This leads to an increasing need of valuation methods to help in sorting out the most promising projects.

These methods range from simple discounted cash flow analysis to more sophisticated methods which incorporate the individual risk of each project as well as simulation tools which help to get insight into the true up- and downsides of a venture. Finally the interrelationship between projects within a portfolio can be analyzed to optimize the selection process.

This thesis is based on the need of finding an appropriate method to determine an indicative value of each project, especially at an early stage of exploration where the uncertainties of the geological and geophysical input parameters are very high. Another aspect is to develop approaches to determine the attractiveness of a project within a short timeframe.

In the course of these objectives, this work compares different evaluation methods on their accuracy as well as the influence of the oil price on the value of different projects. In addition two evaluation methods used by oil companies are presented. Finally several proposals are made for quick look evaluation tools and portfolio ranking factors.

2 Introduction

Since the mid-1980s it became obvious that, globally the average size of new discoveries was diminishing. But exploration still was in search for further giant fields, less than one percent of the exploration ventures were economically successful. In this time companies realized that they needed to adopt systematic procedures to better manage the exploration function, as it is essential in business to invest in projects that are expected to show a profit.[1]

Therefore models were developed to measure the degree of profit of projects and to compare different projects. It is critical to use a consistent ranking process in a portfolio to allocate the budget between the most attractive projects. The models are based on geological and economic input parameters. Unfortunately, in petroleum business it is in the nature of the parameters, that they are underlying a high uncertainty, especially in the early stage of a project. To account for this uncertainty, risk analysis was introduced.

The objective of this thesis is to compare different methods for economic evaluation of the exploration portfolio at an early stage. Further a special interest lies in the determination of an indicative value of prospects with quick-look methods, as it is not appropriate to perform a detailed economic analysis of every prospect at this stage of information. Advantages and shortcomings of different oil price scenarios will be investigated.

Overview of the Following Chapters

The following part shows the general structure of this work and gives a brief overview of the chapters.

Chapter 3 describes the fundamental methodologies and terms needed for the evaluation. It is started with the differentiation of plays and prospects, further the creation of an economic value is described and the terms risk and uncertainty are explained. Methods of economic evaluation are presented in order of increasing sophistication and finally the necessity of portfolio management is explained.

[1] Cf. Rose (2001), p. 1

Chapter 4 gives an overview of the Peter Rose Methodology for prospect evaluation and additionally two company models are presented. Finally the most important publications according to this topic are presented.

Chapter 5 sets the prerequisites necessary for the evaluation, like the actual state of the OMV evaluation process, the definition of the objectives of this thesis and presents the dataset used for the evaluation. Finally a short introduction to the resource definitions OMV uses is given.

Chapter 6 describes the procedure of the evaluation model development. The variables used as well as the assumptions made for the evaluation model are presented.

Chapter 7 shows the results of the evaluation, further some promising approaches for quick look methods are explained.

Finally, **Chapter 8** presents the conclusions and recommendations drawn from this work as well as suggestions for further research on this topic.

3 Methods of Economic Evaluation

After the differentiation of the terms play and prospect, the creation of a project value is discussed and risk and uncertainty are defined. Economic evaluation methods are explained, in order of increasing sophistication: net present value, expected monetary value, decision trees and Monte Carlo simulation. The final part gives a short introduction to portfolio management in petroleum business.

All current and widely used industry measures depend on the fundamental expression of project value which is determined by the net present value.[2] There are further economic measures like maximum negative cash flow[3], investment efficiency[4] or payout time[5]. As these measures are not necessary for the evaluation procedure and are generally used in later stages of the exploration process where detailed information is available, they will not be presented in this thesis.

3.1 Petroleum Systems, Plays and Prospects

As the terms play and prospect are used throughout the entire thesis it is important to understand the difference and the use of them.

A **play** is “a family of geologically related fields, prospects and leads, all of similar geological origin and charged from common petroleum beds”[6].

Prospects on the other hand represent an individual potential accumulation which is perceived to belong to an individual play. The prospect is characterized by risk components and a probability range distribution of potential hydrocarbons volumes confined within its trap.[7]

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[2] Cf. Rose (2001), p. 53

[3] See Rose (2001), p. 54

[4] See Rose (2001), p. 54

[5] See Newendorp (1975), p. 14

[6] Rose (2001), p. 60

[7] Cf. Garcia et al. (2003), p. 2

Origin of a Play and Economic Considerations

By about 1975 explorationists developed the concept of the **petroleum system** (Fig. 3-1). The focus was on the entire petroleum generating basin complex of petroleum source rocks, carrier beds and conduits for migrating petroleum and traps containing the accumulated hydrocarbons. A petroleum system often contains multiple plays with several different trap types all charged from a common petroleum source rock in a petroleum generative depression or so called kitchen.[8]

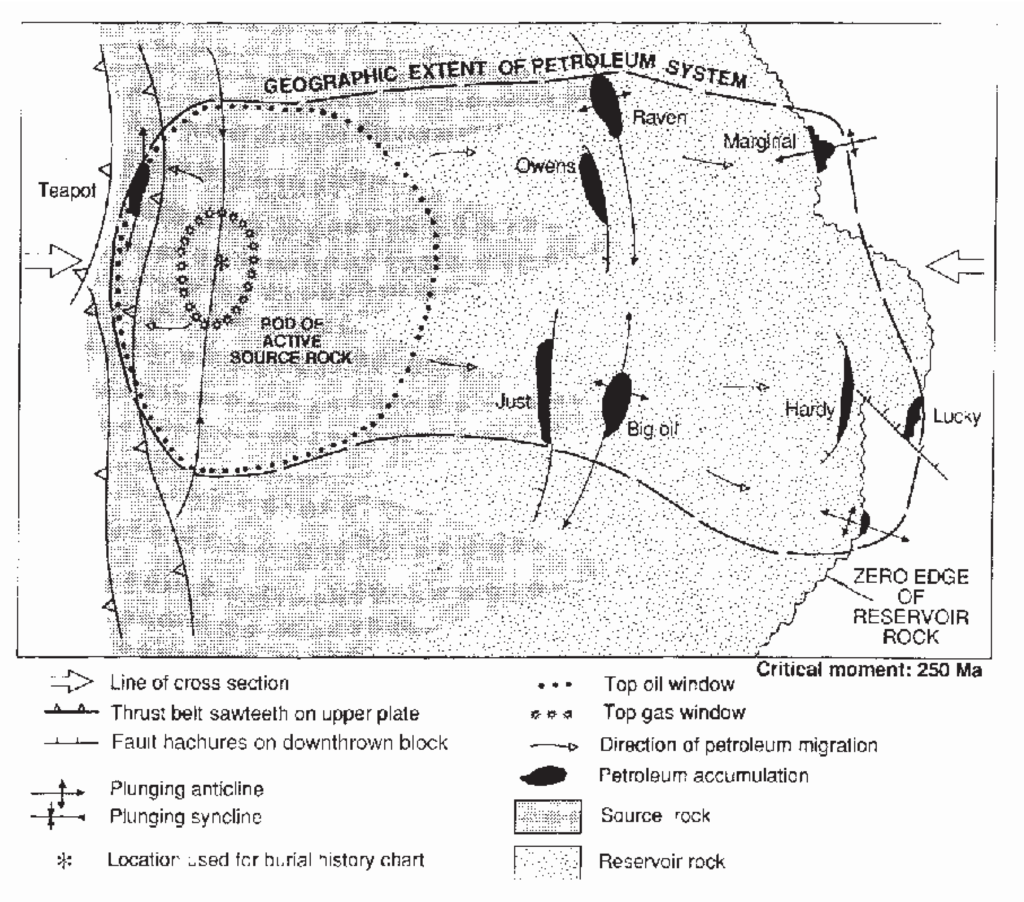

Fig. 3-1: Map of a hypothetical basin showing the areal extend of a petroleum system

Source: Rose (2001), p. 59

Due to the constant features of a play, like similar reservoir types and trap geometries, commonality of hydrocarbon charge, consistent exploration and development methods and uniform contract terms, economic evaluation can be done on a consistent basis and therefore reduce the risk of individual projects in the play. The development of a successful play can be a substantial asset of a petroleum company. Nevertheless, the economic consequences of entering a bad play can be serious as such a venture involves large

[8] Cf. Rose (2001), p. 58

commitments of money, time and personnel. Therefore a key decision of a petroleum company is not which prospect to drill but which play to enter.[9]

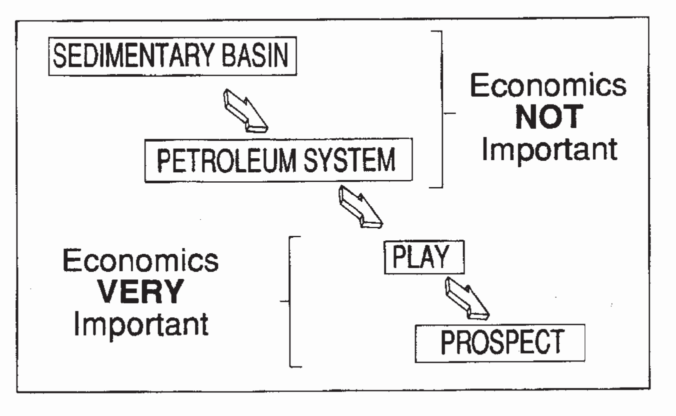

Fig. 3-2: Four levels of petroleum investigation

Source: Rose (2001), p. 61

In general it can be said the level of detail increases with decreasing size of the project (Fig. 3-2). The investigation of a petroleum system with all its complexities and multiple plays is difficult to perform, even if the detailed understanding of such a system could lead to new targets and ideas in development of hydrocarbon resources. Nevertheless, most economic considerations are made on the level of plays and prospects.[10]

3.2 Creating Value

When a promising play is found, the first step in petroleum exploration is the identification of the drilling prospect by geoscientists. This is the basic value-creating act. After the exploration prospect has been identified its value has to be determined.

This is done with the following workflow: [11]

- Estimating how large the producible reserves are likely to be (assuming that hydrocarbons are indeed present).
- Estimating the chance that a producible hydrocarbon accumulation is present.
- Estimating the profitability of the entire project, given that producible hydrocarbons are present.

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[9] Cf. Rose (2001), p. 60 et seq.

[10] Cf. Rose (2001), p. 59 et seq.

[11] Cf. Rose (2001), p. 3

Risk is associated with every economic decision involved in exploring and developing oil and gas resources. Consequently decision analysis in the oil industry has been an active area of investigation for at least 50 years. In this time economic analysis has evolved from single point determinations to more complex, probabilistically driven techniques.

The most common method uses decision trees to derive a risk-weighted mean net present value for the project under consideration. Decision trees are also frequently used to analyze management decisions with the maximum expected monetary value.

In contrast to decision trees, which consider only a small number of scenarios, probabilistic methods cover a wide range of scenarios. Most companies use a mixture of both methods; in particular hydrocarbon volumes are frequently analyzed with probabilistic methods and economics with decision tree analysis.[12]

3.3 Risk and Uncertainty

Every exploration decision involves considerations of both risk and uncertainty. Risk and uncertainty are not synonymous. Uncertainty is not measurable and has in the course of that an unknown probability. Risk is characterized by randomness of an event which can be measured precisely and used for calculations as a consequence.[13]

Garb[14] divided risk into three classifications:

- Technical risk
- Economic risk
- Political risk

The **technical risk** accounts for the uncertainty that the hydrocarbon values estimated by the geologists and engineers do exist in the ground and that the recoverable amounts can be produced within the timeframe projected by the engineers.

Economic risk accounts for the uncertainty of product prices, operating costs, equipment costs, inflation and market conditions.

Finally the **political risk** that world economics, international political stability, taxation and regulations will not be significantly different, than assumed beforehand for the evaluation.

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[12] Cf. Mudford (2000), p. 1

[13] Cf. Shannon and Rigotti (2004), p. 2

[14] Cf. Garb (1988), p. 765

3.4 Time Value of Money and Discount Rate

For companies a main reason[15] to invest in petroleum exploration ventures is the anticipation in receiving a series of future annual cash flows from production revenues. To assess the value of such future cash flows it is important to understand the principle of the time value of money concept.[16]
All of the time-value of money considerations are generally based on the following relation:

The compound interest equation:

$$FV_n = PV(1+i)^n$$ ……………………………………………………………………Equ. 1 [17]

Where:

PV = Present value

FV_n = Future value, "n" years away

i = Interest rate

n = Number of years

$(1+i)^n$ = Compound factor

To determine the present value of future values the equation is rearranged to:

$$PV = FV_n \left[\frac{1}{(1+i)^n} \right]$$ ……………………………………………………………………Equ. 2

Where:

$\frac{1}{(1+i)^n}$ = Discount factor

Thus the discount rate is used to express the time value of money, in other words: what is the value of the future cash flows today[18].

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[15] A company may invest in a project which has no monetary profit, but must be undertaken for other reasons, such as an entry in a new country or legal issues.

[16] Cf. Rose (2000), p. 49

[17] Cf. Frey (1996), p.6

[18] Cf. Newendorp (1975), p. 17 et seq.

It is important to understand that the discount rate selected by the company should be the consistent among all classes of ventures. It should reflect the weighted average cost of capital. Another approach to determine the discount rate is an approximation to the firm's actual long-term average annual rate of return also called the cooperate reinvestment rate.[19]

When companies deliberately choose a high discount rate, one that is significantly higher than their cost of capital or average reinvestment rate, there is the great danger in ruling out long term projects, because cash flows beyond about 15 years have little or no value. Generally these long-lived projects are associated with large-reserve opportunities. Instead, preferentially short-term projects are introduced into the portfolio, with high earning rates but short-lived and have to be replaced relatively fast, which can be difficult.

On the other hand, a too low discount rate results in portfolios containing many long-term, large reserve projects. This can depress the overall present value of the portfolio, but has not such a big influence as a too high rate.[20]

3.5 Net Present Value

Cash flow analysis determines the flows per period of a project. The Net Present Value (NPV) technique values them in today's dollars. With the NPV different projects can be compared regardless of their timing. It is important to note, that a previously specified discount rate is used for all economic analysis.[21]

The basic idea behind the NPV is: A dollar today is worth more, than a dollar received in future.

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[19] Cf. Rose (2000), p. 49

[20] Cf. Rose (2000), p. 49

[21] Cf. Newendorp (1975), p.31

For the calculation of the NPV the following equation is used:

$$NPV = \sum_{t=1}^{N} \frac{C_t}{(1+i)^t} - I_0 \qquad \text{Equ. 3}^{(22)}$$

Where:

C_t = Cash Flow at Period t

I_0 = Initial Investment

N = Total Length of the Project

t = Time Period

i = Cost of Capital

If the NPV is positive the required rate of return has been exceeded and the company can expect an additional profit that has a present value equal to the NPV. Thus, if the goal of the company is to maximize its wealth, projects with a NPV greater than zero should be selected and if two projects are mutually exclusive, the one with the higher net present value should be chosen.[22]

The NPV is the most generally accepted first step in an evaluation of oil and gas prospects. This is just a first step, however, and adjustment for proper assessment of uncertainty is still required to arrive at an expected value.[23]

3.6 The Expected Value Concept

Measures of profitability such as the NPV do not include explicit statements about the degree of risk associated with a given investment or drilling project. The expected value concept is a method for combining profitability estimates with quantitative estimates of risk to yield a risk-adjusted criterion. Various consequences of each decision option can be evaluated and compared.

Quantitative statements about risk are given as numerical probabilities, or likelihoods of occurrence. Probabilities are decimal fractions in the interval zero to one. An event which is certain to occur has the probability of occurrence of one. As the probabilities approach zero, the events become increasingly less likely to occur. The expected value of an outcome is

[22] Cf. Frey (1996), p. 17

[23] Cf. Garb (1988), p. 770

obtained by multiplying the probability of occurrence of the outcome and the conditional value that is received if the outcome occurs.[24]

The word *conditional* means that the value will only be received if that particular outcome occurs. If the conditional values are monetary profits or losses the product is called Expected Monetary Value (EMV) of the outcome. As a criterion to compare competing decisions alternatives the expected value of each possible outcome is added up.[25]

$$EMV = \sum_{n=1}^{N} V_n * P_n \quad \text{Equ. 4}$$ [26]

Where:

V_n = Value if outcome occurs

P_n = Probability that outcome will occur

N = Number of possible outcomes

When choosing among several mutually exclusive decision alternatives select the alternative having the highest positive EMV[27].

The EMV also fulfils several characteristics of a good measure of profitability:[28]

- It is suitable for comparing and ranking the profitability of investment opportunities.
- EMV reflects the firm's time-value of capital.
- The parameter tells whether profitability exceeds some minimum, such as cost of capital and/or the firms average earnings rate.
- It includes a quantitative statement of risk.

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[24] Cf. Newendorp (1975), p. 58 et sqq.

[25] Cf. Newendorp (1975), p. 62

[26] Cf. Newendorp (1975), p. 63

[27] Cf. Newendorp (1975), p. 58 et sqq.

[28] Cf. Newendorp (1975), p. 12

3.7 Decision Tree Analysis

A decision tree is a pictorial representation of a sequence of events and possible outcomes. There is no scale to the decision tree, so the lengths of the lines or the angles of the branches have no significance. The point from where two or more branches emanate is called node. A square denotes a decision node, a square at which the decision maker dictates which branch is followed. A circle is called chance node, a point where chance determines the outcome.[29]

□ = Decision node

○ = Chance node

Either type of nodes can also be used in sequence. The ends of a decision tree are called terminal points, which mean that no further contingencies, decisions or chance events are beyond that point.

The next step is that probabilities of occurrence must be associated to all the branches radiating from chance nodes and conditional values received (e.g. NPV's) must be specified at the terminal points.[30]

Solving a Decision Tree

A decision tree is solved by starting at the end (terminal points) and working backwards. The first step to solve the tree is to compute the expected value using the terminal points around the last chance node in the tree. Always working to the left, each chance node is replaced with the expected value and each choice node with the more attractive alternative. In the end a value is assigned to the initial decision which has the maximum profit or the least loss.[31]

The structure of a simple decision tree is shown in Fig. 3-3. It illustrates the decision alternatives "Drill" and "Do not Drill". If the well is drilled there is a 69% chance of a dry hole and a 31% chance of success, that producible oil is found. The success case is divided into three scenarios with a low, medium and high outcome with chance values added. The NPV's of each case are stated at the terminal points on the right side of the decision tree.

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[29] Cf. Newendorp (1975), p. 108 et sqq.

[30] Cf. Newendorp (1975), p. 108 et sqq.

[31] Cf. Newendorp (1975), p. 111 et sqq.

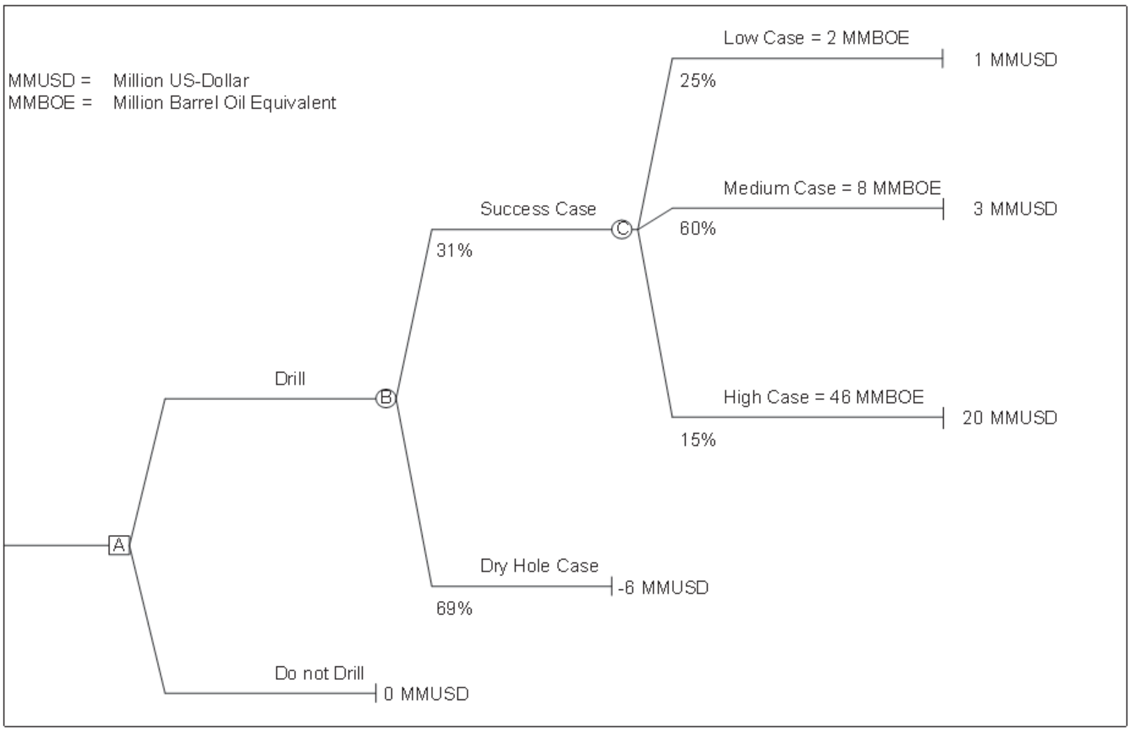

Fig. 3-3: Example Decision Tree

As mentioned above, the decision maker has to start on the right side to solve the tree:

First the EMV of chance node C is calculated

EMV (C) = (0.25*1)+(0.6*3)+(0.15*20) = 5.05 MMUSD

Chance node B is calculated the same way:

EMV (B) = (0.31*5.05)+(0.69*(-6)) = -2.57 MMUSD

Finally the decision maker has the decision at node A between

- either to drill and have an expectation to loose 2.57 MMUSD
- or not to drill and have an expectation of zero USD.

As the branch with the more attractive alternative is “Do not Drill” the decision maker should select this choice.

3.8 Monte Carlo Simulation

The term and the use of Monte Carlo simulation are explained at the beginning of this chapter, followed by a more detailed discussion about the different distributions and possible dependencies of the variables. Finally a short introduction to random number generation is given and the importance of sensitivity analysis is shown.

3.8.1 Monte Carlo Simulation Basics

The word simulation refers to any analytical method meant to imitate a real-life system, especially when other analyses are too mathematically complex or too difficult to reproduce.

Without the aid of simulation, a spreadsheet model will only reveal a single outcome, generally a most likely or average scenario. Spreadsheet risk analysis uses both a spreadsheet model and simulation to automatically analyze the effect of varying inputs on outputs of the modeled system.
Monte Carlo simulation calculates multiple scenarios of a model by repeatedly sampling values from probability distributions for the uncertain variables and using those values for the cell. Simulations can consist of as many trials (or scenarios) as needed, hundreds or even thousands. During a single trial, the simulation program randomly selects a value from the defined possibilities for each uncertain variable and then recalculates the spreadsheet.[32]

3.8.2 The Use of Monte Carlo Simulation in Analyzing a Project

To determine a monetary value of a project the following steps have to be used in general:[33]

1. Definition of the variables
2. Sorting of the variables into two groups
3. Definition of the distribution for all unknown variables
4. Running of Monte Carlo simulation
5. Interpretation of the results

[32] Cf. http://www.decisioneering.com/monte-carlo-simulation.html

[33] Cf. Newendorp (1975), p. 377

Definition of the variables: The variables, which affect the desired profit indicator (e.g. NPV), have to be determined. The most relevant and obvious are reservoir volume, well productivity, number of wells to be drilled, operational expenditures (OPEX) and capital expenditures (CAPEX), dry hole costs, etc.[34]

Sorting of the variables into two groups: The variables are sorted into two groups; the first group for variables whose values are known with certainty and the second group are the unknown or random variables for which exact values cannot be specified at the moment. In exploration prospect analysis most of the variables affecting profitability will end up in the second group like the amount of recoverable reservoir volume, future oil price and so on. Known parameters can be taxes or royalties.[35]

Definition of the distribution for all unknown variables: Each distribution should be identified by type, e.g. lognormal, normal, triangular or uniform (Fig. 3-4), and by defining parameters like mean and standard deviation, or min, mode and max.

Fig. 3-4: Lognormal, normal, triangular and uniform distribution
Source: Goldman (2000), p. 3

The particular distribution for a parameter can be selected by:

- empirical data that was fit by software
- experience
- fundamental principal

Further, each distribution should be defined as uncorrelated (independent) or correlated. If the distribution is correlated the coefficient has to be determined, e.g. with data analysis or again due to fundamental principals. The resulting coefficient can be implemented into the simulation. [36]

Running of Monte Carlo simulation: Now Monte Carlo simulation can be run. The simulation is a succession of hundreds or thousands of repeated trials. A trial consists of

[34] Cf. Frey (1996), p. 35
[35] Cf. Newendorp (1975), p. 378 et sqq.
[36] Cf. Peterson et al. (2005), p. 5

randomly selecting one value for each input parameter and calculating the output. One trail represents a particular realization of the analyzed project. The calculated trails are collected in a file in the computer memory and afterward the output values are grouped into a histogram or cumulative distribution function.
A by-product of the simulation is a sensitivity chart. A measure of significance toward a given output variable is calculated for each input variable. As models become more complex, sensitivity analysis identifies the driving variables that merit additional scrutiny and so helps to reduce effort wasted on unimportant things.[37]

Interpretation of the results: For every model a set of outputs is generated, as a basis for further analysis.

3.8.3 Distributions

Three terms are used frequently to reflect representative parameter developed from distribution curves: mean, median and mode (Fig. 3-5).

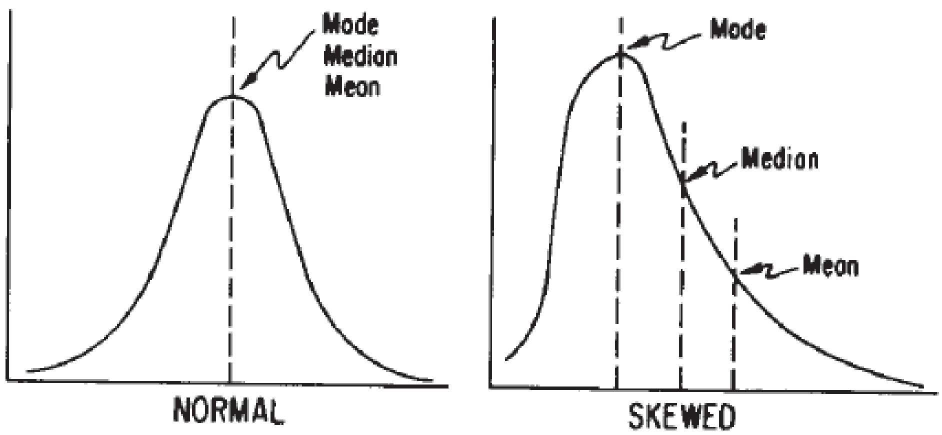

Fig. 3-5: Location of mean, median and mode on normal and skewed distribution
Source: Garb (1988), p. 772

With a symmetrical bell-shaped curve, these parameters are all identical in value; with a skewed curve they are different. The mean is commonly applied to the arithmetic average; it is simply the sum of the variables divided by their total number.[38]
For skewed distributions the statistical mean should be preferred. Therefore a continuous distribution has to be assumed with contribution from values greater than the first percentile:[39]

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[37] Cf. Murtha (1997), p 361 et seq.
[38] Cf. Garb (1988), p. 772

Statistical Mean = $e^{\mu+\sigma^2/2}$ ………………………………………………………………Equ. 5 [(40)]

Where:

μ = *ln* median

σ = *ln* standard deviation

The median is the value in the set of numbers that occurs at the midpoint of the set. The value of the median exceeds one-half of the values in the array of numbers and is exceeded by the other half. The mode is the value that occurs most frequently.[41]

There are two common formats for probability distributions: a Cumulative Distribution Function (CDF) which is a nondecreasing/ nonincreasing function whose y values range from zero to one. The second format is the derivative of the CDF and called a Probability Density Function (PDF). Fig. 3-6 shows both plots for a normal distribution. Generally the CDF presentation is more useful but often the PDF may be more familiar.[42]

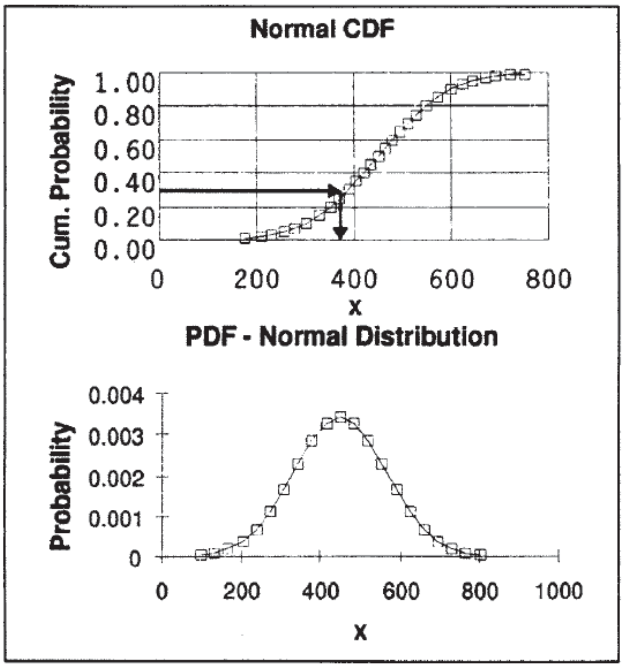

Fig. 3-6: Example for a CDF and PDF

Source: Murtha (1997), p. 362

[39] Cf. Rose (2001), p. 125

[40] Cf. Rose (2001), p. 125

[41] Cf. Garb (1988), p. 772

[42] Cf. Murtha (1997), p. 362

A common use of the CDF is to specify certain values of the variable X. The expression P10 meaning the 10^{th} percentile, is the value X corresponding to 0.10 on the cumulative probability axis. Of particular interest is the median P50, the mean which is the arithmetic average value and the mode as the most popular range. [43]

In petroleum business the P10 and P90 values are often interchanged: P10 is associated to the optimistic estimate and P90 to the pessimistic estimate. In general, the estimate Pn means that there is n% of probability that the real value will be the same or superior to the estimated value (Fig. 3-7).[44]

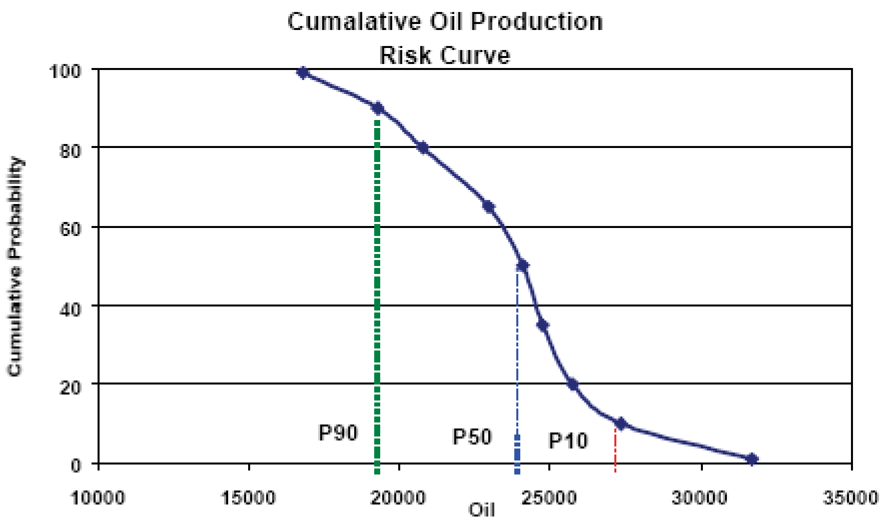

Fig. 3-7: Risk curve of cumulative oil production with P90, P50 and P10 values

Source: Steagall et al. (2001), p. 6

Common Types of Distributions:

Normal distribution: The normal distribution is probably one of the most common and widely used distributions in statistics and probability theory. It is a continuous probability distribution having a symmetrical shape similar to a bell; it is also called Gaussian distribution. A typical example for a variable represented by a normal distribution is porosity.[45]

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[43] Cf. Murtha (1997), p 361 et seq.

[44] Cf. Steagall et al. (2001), p. 1 et seq.

[45] Cf. Newendorp (1975), p. 257

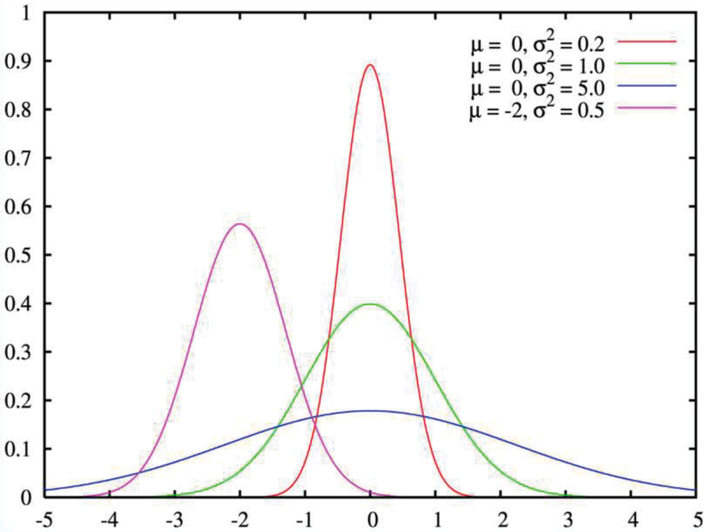

Fig. 3-8: In green the standard normal distribution

Source: Wikipedia: http://en.wikipedia.org/wiki/Normal_distribution

Lognormal distribution: Lognormal distributions are often used to describe reserve data or recovery data. It appears similar to a normal distribution except, that the function is skewed to one side The lognormal distribution shown in Fig. 3-9 describes a random variable which has a small chance of large numerical values and a large chance of smaller numerical values of the variable.[46]

Both normal and lognormal distribution can be defined completely and uniquely by the two single value parameters μ and σ.

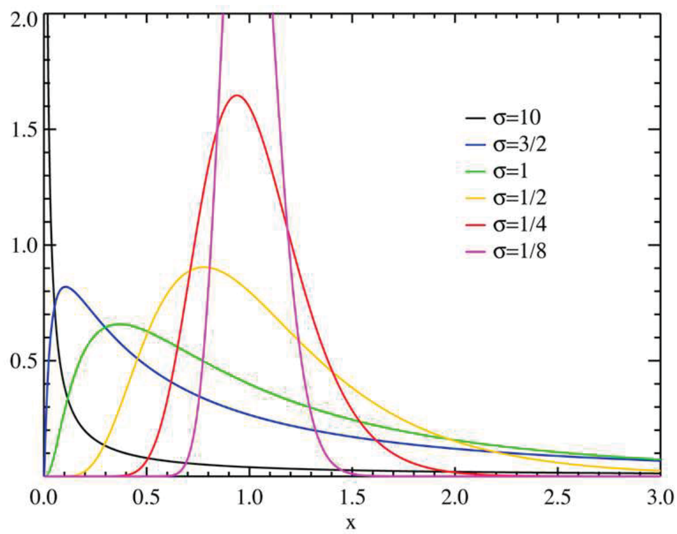

Fig. 3-9: Example of lognormal distributions

Source: Wikipedia: http://en.wikipedia.org/wiki/Lognormal_distribution

[46] Cf. Newendorp (1975), p. 267

Uniform distribution: The uniform distribution is a continuous probability distribution describing a random variable in which any numerical value of the variable is equally likely to occur with an upper and a lower limit[47].

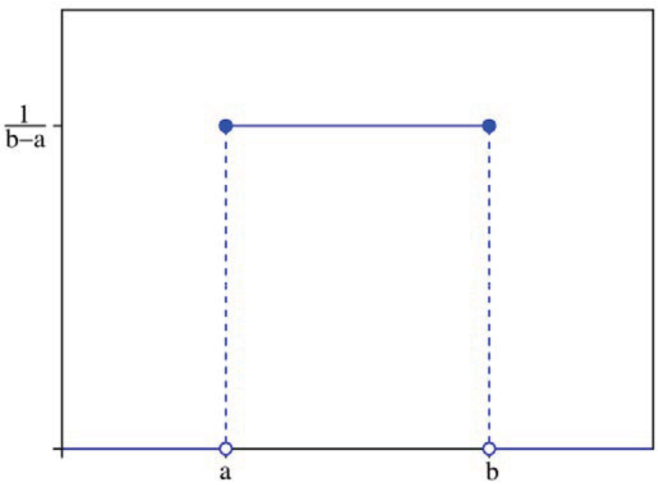

Fig. 3-10: A uniform distribution with lower (a) and upper (b) limit

Source: Wikipedia: http://en.wikipedia.org/wiki/Uniform_distribution_%28continuous%29

Triangular distribution: Another common distribution is the triangular distribution. The triangle can be symmetrical or skewed in one direction. It is completely specified by the minimum, most likely and maximum values of the random variable.[48]

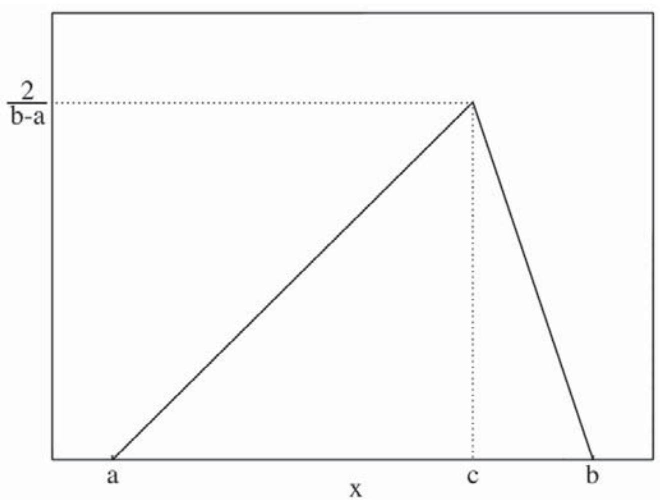

Fig. 3-11: A negative x skewed triangular distribution

Source: http://en.wikipedia.org/wiki/Triangular_distribution

[47] Cf. Newendorp (1975), p. 271

[48] Cf. Newendorp (1975), p. 273

3.8.4 Dependency between Variables

Some of the variables can be related to another, in which case the dependency relationship should be defined. This can be done by plotting one variable vs. another.

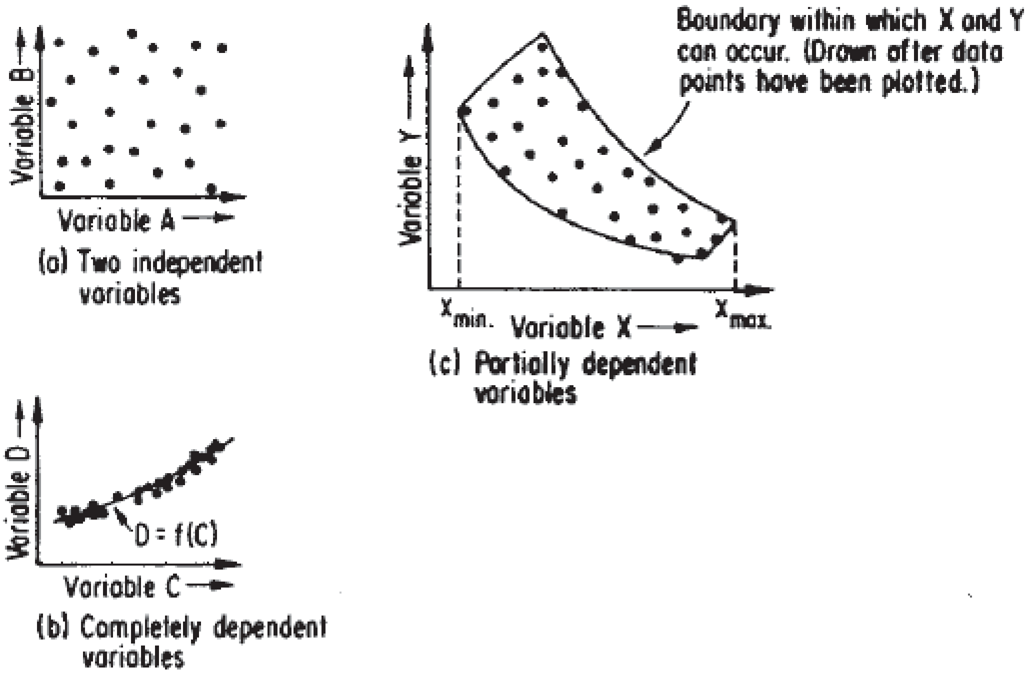

Fig. 3-12: Graphic determination of dependency between variables

Source: Garb (1988), p. 771

If the plot shows a complete random scatter the variables are independent (Fig. 3-12a). Partial dependency shows a definite trend between the variables which can be defined by an envelope which drawn around the data points (Fig. 3-12c). Completely dependent variables follow a specific trend (Fig. 3-12b) and when entering the cross plot one variable can be determined by the corresponding value of the other.[49] By entering the coefficient into a correlation matrix the simulation software can honor the relationship.

3.8.5 Random Numbers

All Monte Carlo methods need an underlying random number generator. This driving engine supplies variate vectors, which in limit of infinitely many draws, satisfy a given joint multivariate distribution density function. This is typically done by transformation of draws from the uniform distribution of equal probabilities for all numbers of the interval (0,1), where

[49] Cf. Garb (1988), p.771

both zero and one are excluded, as for most distributions at least one of the two endpoints represent plus or minus infinity, which poses a numerical problem.

Traditionally, Monte Carlo techniques used to depend on a number generation method that mimics randomness as well as possible. The problem with these random numbers actually is “that a machine that is designed to follow instructions in a deterministic way, such as a computer, cannot produce anything that is actually random”[50].
Therefore modern methods pay great attention to achieve very long periodicities of the number generator, but still tests can be constructed, that will prove it to be non random. For this reason computer-generated random numbers are referred to as pseudo-random numbers.[51]

Monte Carlo Sampling

Once a variable X is described by its CDF, a Monte Carlo sample can be obtained by first generating a random value of the uniformly distributed probability function on the y-axis. By taking the inverse function of that value from the CDF curve an X-value is received (Fig. 3-13).[52]

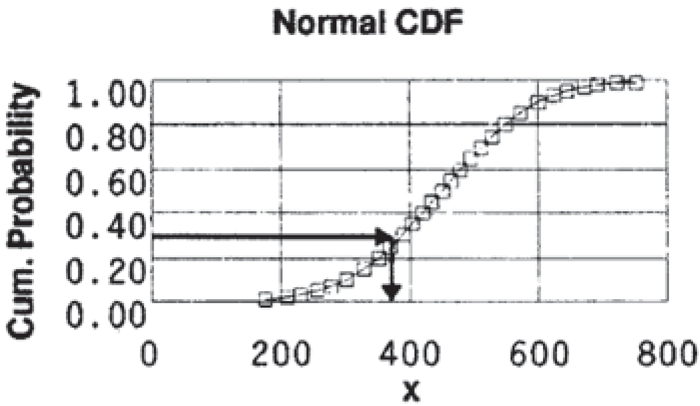

Fig. 3-13: Example of Monte Carlo Sampling
Source: Murtha (1997), p. 362

Although, the random variable is distributed uniformly, it can happen, that at a low number of trials, the random numbers accumulate at certain areas of the distribution and so influence the result. To overcome this problem more sophisticated methods for sampling were developed.

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[50] Jäckel (2002), p. 67

[51] Cf. Jäckel (2002), p. 67

[52] Cf. Murtha (1997), p. 362

Latin Hypercube Sampling

As a complete discussion of the advantage and shortcomings of different random number generators would go beyond the scope of this thesis, only Latin Hypercube sampling, which was used for the evaluation, will be explained here.

The sampling scheme is an attempt to place sampling points in a multidimensional stratification with as little overlap in all one-dimensional projection as possible. If, for example, there are 4 parameters, and for each of the parameters 7 different settings are possible, which represents a four-dimensional stratification, $7^4 = 2401$ tries would be needed to get an idea what the optimal combination of settings would be.
The Latin Hypercube scheme is a systematic method to sample the stratified layer in each control parameter at least once[53]. An example of such an arrangement is shown in Fig. 3-14:

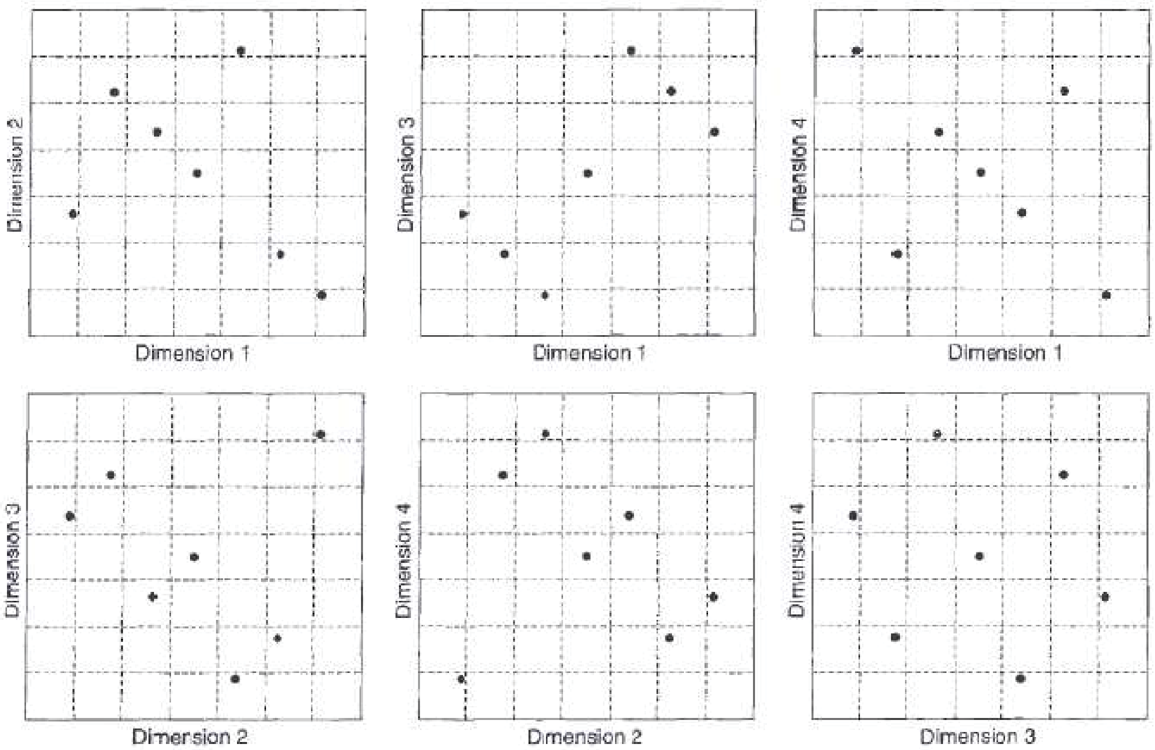

Fig. 3-14: The Latin Hypercube arrangement of sampling points
Source: Jäckel (2002), p. 121

[53] Cf. Jäckel (2002), p. 119 et seq.

3.8.6 Sensitivity Analysis

"Sensitivity Analysis (SA) is the study of how the variation in the output of a model (numerical or otherwise) can be apportioned, qualitatively or quantitatively, to different sources of variation" [54].

One of the by-products of the simulation run is a sensitivity chart shown in Fig. 3-15:

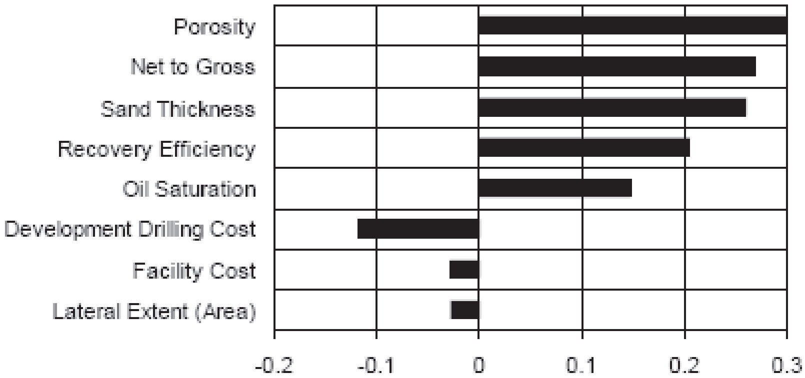

Fig. 3-15: Sensitivity of the NPV with the correlation coefficient on the x-axis

Source: Hooper III (2001), p. 7

A measure of significance toward a given output variable is calculated for each input variable, namely the (rank-order) correlation coefficient between the two parameters. The coefficients can range from minus one to one. In the upper example the porosity has the main influence on the NPV. In complex models, SA identifies the driving variables. It is also important to note, that imposing a correlation upon variables can reorder the list of sensitivity variables.[55]

[54] http://sensitivity-analysis.jrc.cec.eu.int/

[55] Cf. Murtha (1997), p. 362

3.9 Portfolio Management

In petroleum business managers are constantly faced with the decision of how to invest a limited amount of capital in order to maximize return. In general all available investments are evaluated and a subset is selected to invest. This subset of investments is often referred to as the company's portfolio. As the selection of this portfolio is critical to a company's success it requires significant considerations. To select an optimal set of projects which matches company strategy and goals is called portfolio management. The main elements that have to be taken into account in portfolio management are:[56]

- Maximization of the portfolio value
- Limited amounts of capital
- Meeting the production requirements
- Achieving short and long term cash flow goals
- Meeting developmental or environmental constraints
- Matching forecasted net income targets

To optimize a portfolio the individual uncertainties of a project have be to known to define the risk of the overall portfolio. By defining this portfolio risk different portfolios can be compared by their risk versus reward relationship.[57]

In 1952 Harry Markowitz explained the theory of portfolio diversification from the perspective of minimizing risk. The three basic principles of this theory are:[58]

- A rational investor will prefer more value to less value but will also prefer less risk to more risk.
- A portfolio can be more or less than the sum of its individual projects, depending on how they interact with each other. The interaction between the investments is as important as the investments themselves.
- There is no single optimal portfolio as it is generally possible to gain more value by accepting more risk.

[56] Cf. Tyler and McVean (2001), p. 1
[57] Cf. Tyler and McVean (2001), p. 1
[58] Cf. Tyler and McVean (2001), p. 2

The last point is essentially an expression of the concept of efficient portfolios. “A portfolio is said to be more efficient if it is the case that no other portfolio has more value while having the same or less risk and there is no other portfolio that has less risk while having the same or more value”[59].

In order to evaluate the efficiency of any given portfolio it is plotted on an efficient frontier graph.

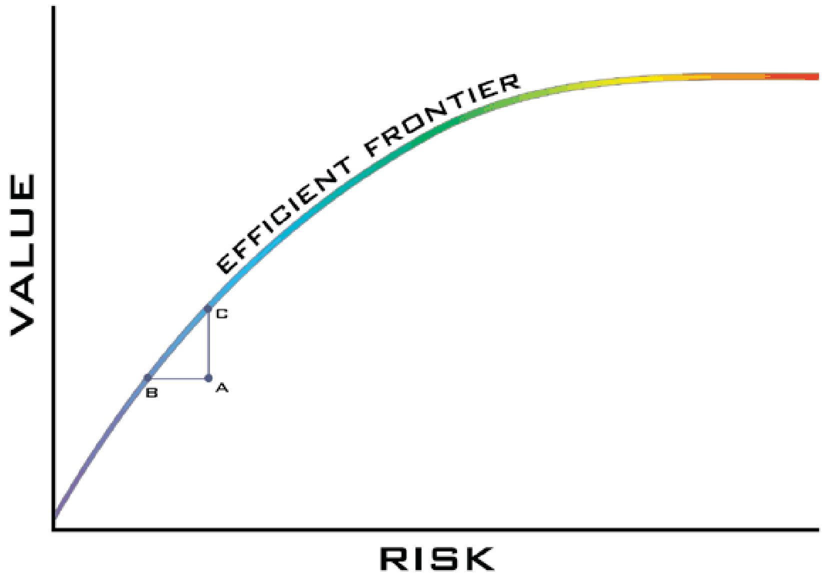

Fig. 3-16: Efficient frontier graph

Source: Schlumberger:

http://www.slb.com/content/services/software/valuerisk/expert_paper_monte_carlo.asp?

It can be seen in Fig. 3-16 that portfolio A is inefficient because there are portfolios with the same value and less risk (portfolio B) and portfolios with the same risk but more value (portfolio C).

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[59] Tyler and McVean (2001), p. 2

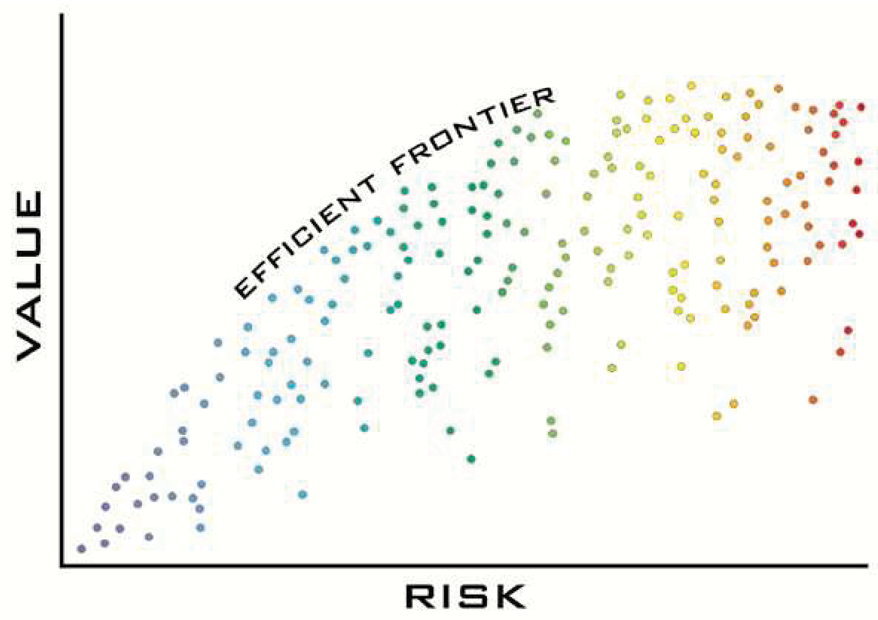

Fig. 3-17: Sampling of possible combinations of portfolios
Source: Schlumberger:
http://www.slb.com/content/services/software/valuerisk/expert_paper_monte_carlo.asp?

By sampling possible portfolio combinations an efficient frontier can be determined as the upper boundary beyond no portfolios exists (Fig. 3-17).

3.9.1 Portfolio Theory in Petroleum Business

As Markowitz portfolio theory applies to investments in stocks for exploration and production (E&P) projects the following differences have to be taken into account:[60]

- Stock portfolios depend only on uncertain returns while E&P projects face on the one hand local uncertainties, which involve the discovery and production of oil at a given site, and on the other hand global uncertainties like prices and politics. Furthermore, the uncertainties in stock returns follow bell shaped curves, while in E&P business uncertainties are highly skewed and stress rare events.
- While historical data exists for stock prices, in E&P uncertainties must be modeled by decision trees or Monte Carlo simulation.
- Risk in stock portfolios is usually measured in terms of volatility, like the degree to which a portfolio swings in value. For E&P portfolios the downside risk has to be tracked down specifically.

[60] Cf. Ball Jr. and Savage (1999), p. 74

- Stocks can be bought in or sold at will, while E&P projects pay out over long time periods.[61]
- A stock portfolio generally contains a small fraction of the outstanding shares of any one company. An E&P portfolio often contains 100% of its constituent projects creating budgetary effects.

These characteristics of petroleum projects have to be accommodated in models to optimize an E&P portfolio.

3.9.2 Lognormality and the Performance of Prospect Portfolios

The beforehand mentioned lognormality of E&P projects also leads to a natural pattern of annual portfolio outcomes: predominately mediocre annual results punctuated occasionally by exceptionally good years and bad years. This is the natural consequence of repeated sampling from lognormal prospect reserves distributions and may have nothing to do with technical or managerial skill. Therefore, a continual reorganization of the ongoing exploration program to improve the year-to-year exploration results may cause more damage than benefits.[62]

To predict the portfolio performance a certain number of prospects is needed. In general it can be said that with increasing number of prospects in a portfolio the accuracy of prediction is increasing as well (Fig. 3-18). The actual number is dependent on the individual prospect reserve variance and the chance of prospect success. For a conservative portfolio with low risk and low variance prospects as few as 40 prospects can be sufficient to provide an 80% predictive confidence. On the other end, a portfolio with high risk and high variance prospects an inventory of 250 wells and more might be necessary to provide adequate confidence in the forecast outcome.[63]

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[61] E&P projects can be sold as well, but the asset turnover is more complex.

[62] Cf. Rose (2001), p. 100

[63] Cf. Rose (2001), p. 102 et sqq.

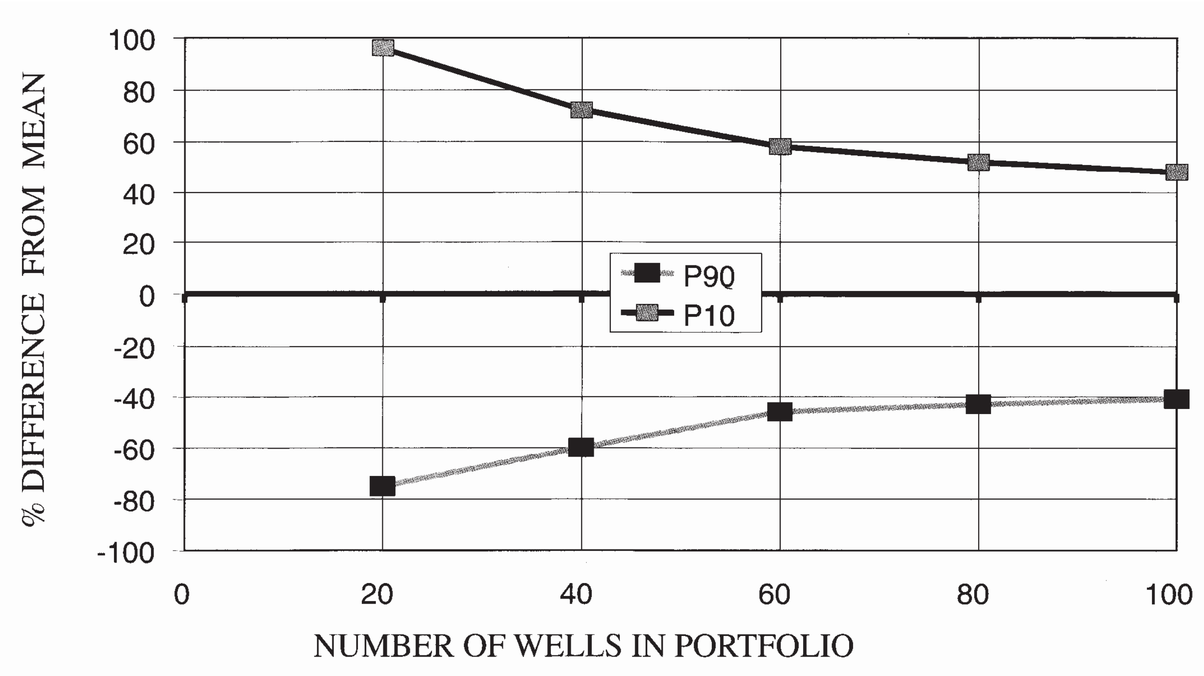

Fig. 3-18: Predictive accuracy of portfolio performance

Source: Rose (2001), p. 104

If the portfolio size is not adequate to deliver the expected confidence in forecast outcomes the following solutions exist:[64]

- More wells can be added to the portfolio, which has the downside of proportionally increasing exploration expenditures.
- Participating in more joint-venture wells, which lead to an increased sample size without significant increase of total exploration expenditures.
- Replacing some high risk wells with more low risk wells. This has the downside of substantial reductions in reserves potential.
- Focusing geotechnical exploration tools on high risk wells to improve confidence in critical geologic factors and raise the probability of success.

[64] Cf. Rose (2001), p. 104

3.9.3 Maintaining an Exploration Portfolio

In maintaining prospect portfolios the following characteristics and difficulties have to be addressed:

Many exploration contacts require that certain wells have to be drilled regardless of how those wells compare with other prospects in the portfolio. If such obligatory wells are included in the ranking process of the portfolio, it is only for the purpose of general comparison and to allow the better obligatory wells to be drilled earlier rather than later.[65]

It is important that the ranking of prospects in the portfolio is equitable a consistent for all divisions and regions. This can be achieved by using a consistent evaluation process by all groups of the company. Further the predictions versus results can be analyzed to reveal groups that consistently demonstrate bias in their forecast whereas the management should honor professional accuracy and integrity of the predictions.[66]

Another aspect of portfolio management is the timing of the cash flows. Ideally large development projects should be started when excess cash from production revenues is available. As this is seldom possible, two noncompeting portfolios can be set up, one composed of low risk ventures that could generate cash near-term and a second high risk portfolio that could provide the growth for the company.[67]

[65] Cf. Rose (2001), p. 105 et seq.

[66] Cf. Rose (2001), p. 105 et seq.

[67] Cf. Rose (2001), p. 105 et seq.

4 Evaluation Models

In this chapter an overview of different economic evaluation models is given. As the OMV evaluation is based on the Peter Rose Methodology it is described in detail in the first part. Further the author had the chance to contact the Chief Economist Roger Burrows at Petro Canada and additionally get insight into a method developed at Fletcher Challenge Energy, New Zealand. Finally papers are presented which proved to be important for this work.

4.1 Peter Rose Methodology

The Peter Rose Methodology (PRM) is similar to the Monte Carlo method, as it enables all required parameter ranges to be input as probability distributions and then to be combined to yield a probability distribution for in place volume and prospective resources. The PRM uses lognormal distributions as input. The distributions are determined by plotting the optimistic (P10) and the pessimistic (P90) case on a log probability graph. [68]

A straight sloping line is drawn between the two points and then extended out to the P1 and P99 extremes, which are evaluated for plausibility. P1 and P99 represent extremes which are highly unlikely but still possible. In case of reservoir size P1 represents the maximum size that can be expected from the data and on the downside P99 a very small detectable accumulation. If any of the derived values is implausible, the line is adjusted until a credible best fit is achieved. This procedure is repeated for each of the necessary parameters. Peter Rose uses the prospect area, average net pay and the hydrocarbon recovery factor.[69]

The resulting independent lognormal distributions are combined using a graphical method (Fig. 4-1), where each P90, P50 and P10 value is multiplied with the corresponding P-value of the other distributions. It is important to note, that the multiplication of three P90 values yield a value corresponding P98.7 and accordingly the multiplication of three P10 values a P1.3 product. Only the product of P50 values result again in a P50 value. Additionally the variance of the input lognormal distribution should not be drastically different.

The resultant prospect reserves are plotted into a lognormal graph, as the multiplication of three constituent independent variables is expected to take a lognormal form. Finally, the

[68] Cf. Rose (2001), p. 17 et seq.

[69] Cf. Rose (2001), p. 18 et seq.

P90 and P10 values are determined from the reserve distribution and the mean is calculated using Swanson's rule.[70]

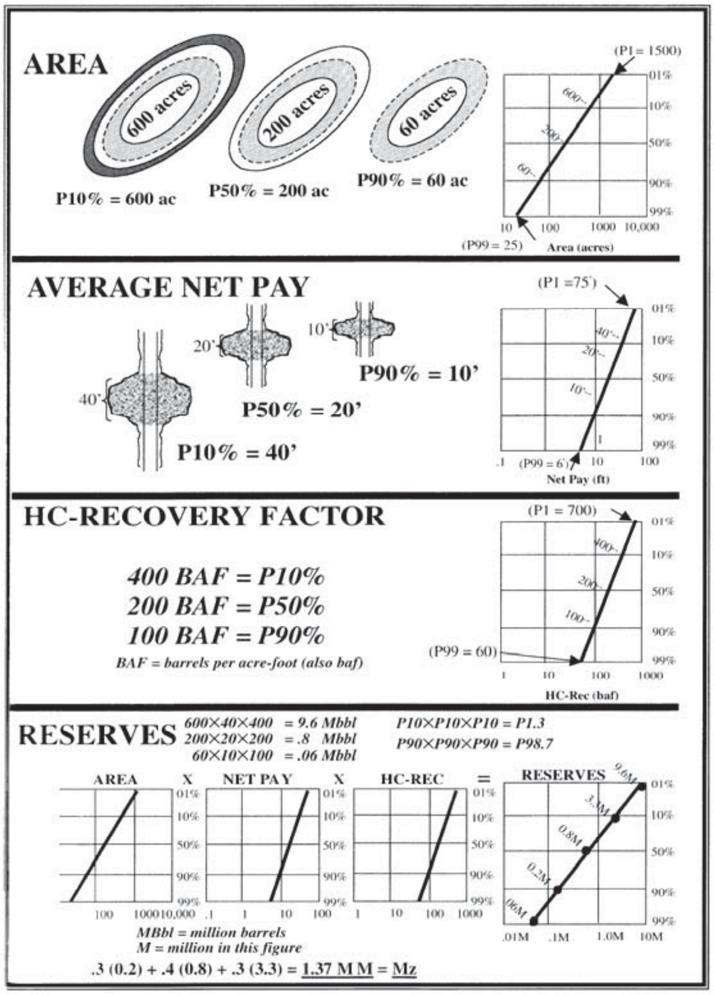

Fig. 4-1: Graphical method for combining lognormal distributions

Source: Rose (2001), p. 25

4.1.1 Swanson Mean

In Fig. 4-1 the mean reserves are calculated using the Swanson mean. Swanson discovered empirically that a good approximation of the mean of a modestly skewed lognormal distribution can be derived by the following formula:[71]

0.3*P90 + 0.4*P50 + 0.3*P10 = Mean

[70] Cf. Rose (2001), p. 24 et sqq.

[71] Cf. Megill (1984), p. 187

However, Swanson's rule must be used with caution when the distributions are highly skewed. In general, if the ratio of the value at P10 to P50 exceeds five the Swanson mean should not be used.[72]

4.1.2 Risking Parameters

Peter Rose introduces three parameters for risking a prospect (Fig. 4-2). They are: **Geological Chance of Success** (Pg), **Commercial Chance of Success** (Pc) and **Economic Chance of Success** (Pe).

The **Geological Chance of Success** is the chance of finding at least the P99 value of resources. Pg has no economic implication as it shows only the technical chance of finding an accumulation capable of sustained flow to the surface. The Pg is estimated directly multiplying the probability of occurrence of five key elements which are: source, timing/migration, reservoir, closure and containment factors.[73]

The **Commercial Chance of Success** is calculated using the Minimum Commercial Field Size (MCFS) to truncate the reserve distribution and calculate the probability to find the MCFS or larger (P_{MCFS}). The MCFS is the smallest resource size that generates a positive NPV considering only cost to complete, connect and operate the field. When the Minimum Commercial Field Size is plotted on the reserves probability distribution curve P_{MCFS} can be extracted from the diagram. Pc is calculated when Pg is multiplied by P_{MCFS}. As Pc considers all prior costs as sunk, it considers the success of an operation only on a point forward basis.[74]

Finally, the **Economic Chance of Success** is calculated similar to Pc, but considering all costs needed to explore, complete, connect and operate the well or field. The Minimum economic field size is the smallest reserve size that generates a positive NPV considering all costs mentioned above.[75]

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[72] Cf. Megill (1984), p. 187 et seq.

[73] Cf. Rose (2001), p. 32 et seq.

[74] Cf. Rose (2001), p. 38 et sqq.

[75] Cf. Rose (2001), p. 38 et sqq

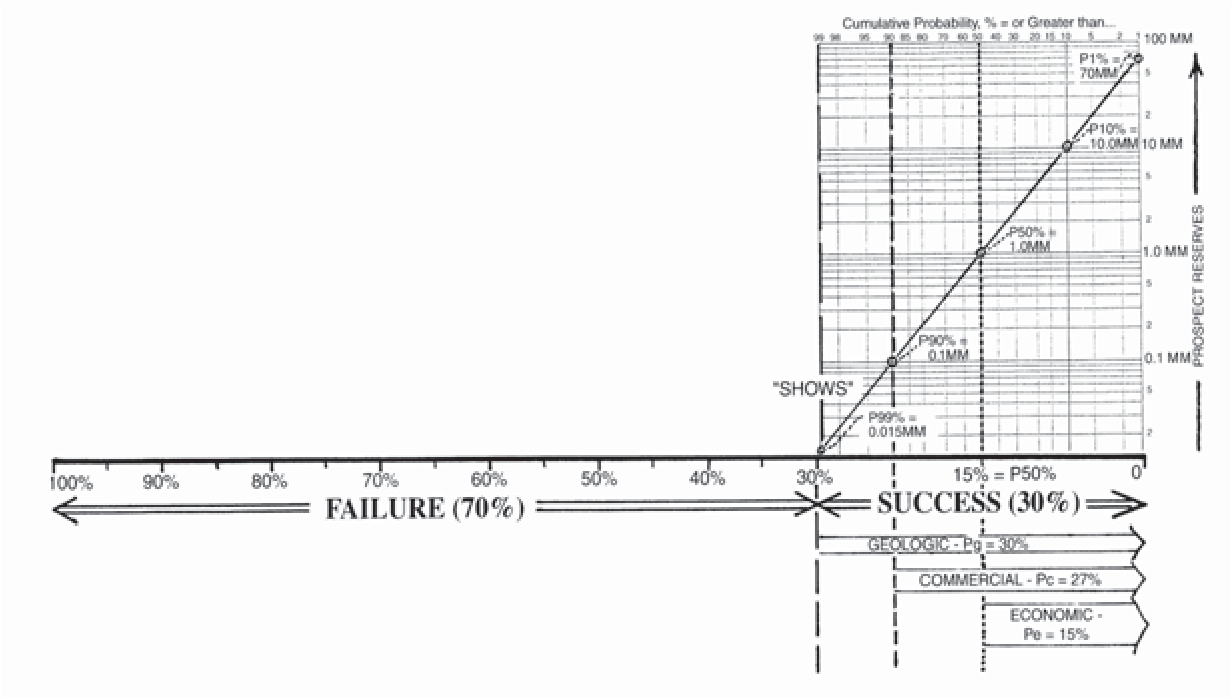

Fig. 4-2: Exploration failure and exploration success (geologic, commercial and economic)
Source: Rose (2001), p. 32

4.1.3 Economic Truncation

Rose mentioned that people are tempted to truncate all projects at the economic threshold, rather than the commercial threshold. This conservative position tends to prevent participation in many projects that could well be profitable. Therefore the criterion should rather be that the average of the entire reserve distributions above the commercial cutoff should be economic.[76]

4.2 Company Models

In the first part the results of a phone call (May 2006) with Roger Burrows, Chief Economist of Petro-Canada are presented. In the second part a method is described, John M. Anderson, OMV New Zealand, was able to provide as he used it at Fletcher Challenge Energy, New Zealand.

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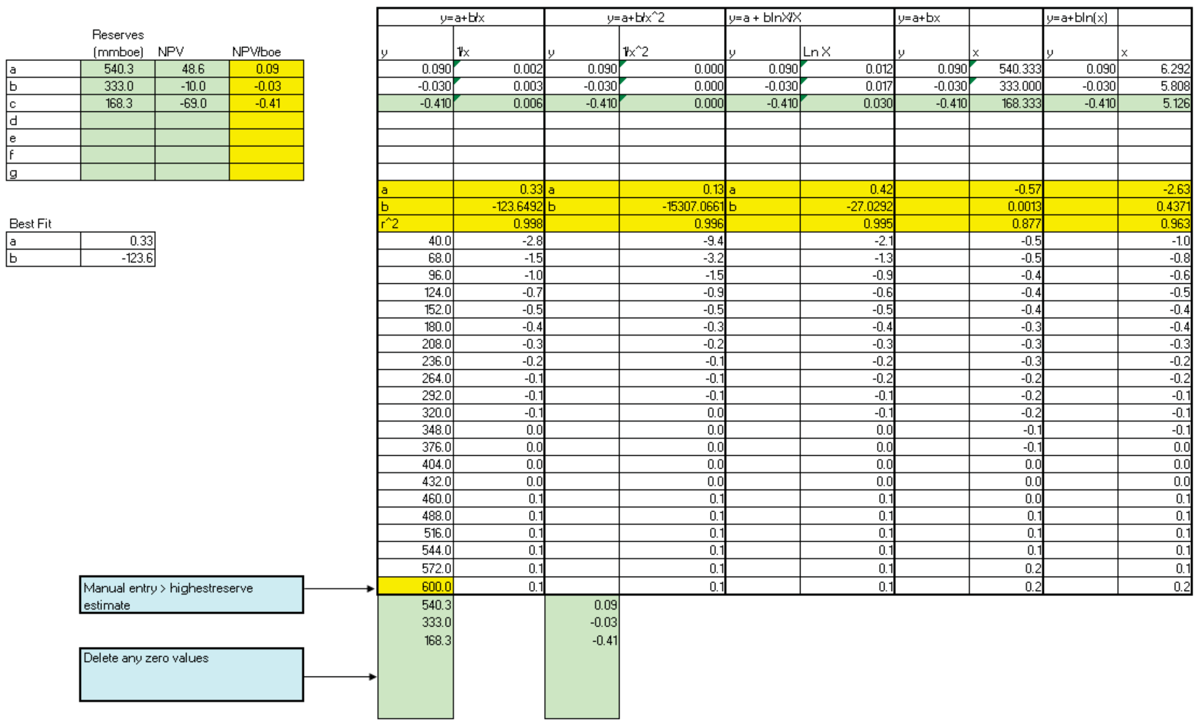
[76] Cf. Rose (2001), p. 40

4.2.1 Petro Canada Model

This method is used for estimation of the most likely reservoir volume and the MCFS. As input at least three reserve values are entered into the spreadsheet, typically the P90, P50 and P10 value. For each of these values a NPV is calculated and in a further step a NPV per BOE value determined. A spreadsheet calculation is used to fit several functions to these values with linear regression. The selection of these functions is based on the experience that most economic measures can be modeled with them. The function a+bx is primarily used for incremental fields in combination with a production sharing contract as these circumstances can be best described by a straight line. Additionally, it can be used as a last resort when other functions do not fit the data.

The NPV per BOE data is used as Y-values for the regression. The reserve volumes are recalculated according to the given functions to determine the X-value. For example: one divided by the reserve value for b/x. With these values the regression parameters a, which is the intercept and b, the slope, are determined by Excel (Fig. 4-3). Also the coefficient of determination is calculated to find the best fitting function.



	Reserves (mmboe)	NPV	NPV/boe
a	540.3	48.6	0.09
b	333.0	-10.0	-0.03
c	168.3	-69.0	-0.41
d			
e			
f			
g			

Best Fit

a	0.33
b	-123.6

y=a+b/x		y=a+b/x^2		y=a + blnX/X		y=a+bx		y=a+bln(x)	
y	1/x	y	1/x^2	y	Ln X	y	x	y	x
0.090	0.002	0.090	0.000	0.090	0.012	0.090	540.333	0.090	6.292
-0.030	0.003	-0.030	0.000	-0.030	0.017	-0.030	333.000	-0.030	5.808
-0.410	0.006	-0.410	0.000	-0.410	0.030	-0.410	168.333	-0.410	5.126
a	0.33	a	0.13	a	0.42		-0.57		-2.63
b	-123.6492	b	-15307.0661	b	-27.0292		0.0013		0.4371
r^2	0.998		0.996		0.995		0.877		0.963
40.0	-2.8		-9.4		-2.1		-0.5		-1.0
68.0	-1.5		-3.2		-1.3		-0.5		-0.8
96.0	-1.0		-1.5		-0.9		-0.4		-0.6
124.0	-0.7		-0.9		-0.6		-0.4		-0.5
152.0	-0.5		-0.5		-0.5		-0.4		-0.4
180.0	-0.4		-0.3		-0.4		-0.3		-0.4
208.0	-0.3		-0.2		-0.3		-0.3		-0.3
236.0	-0.2		-0.1		-0.2		-0.3		-0.2
264.0	-0.1		-0.1		-0.2		-0.2		-0.2
292.0	-0.1		-0.1		-0.1		-0.2		-0.1
320.0	-0.1		0.0		-0.1		-0.2		-0.1
348.0	0.0		0.0		0.0		-0.1		-0.1
376.0	0.0		0.0		0.0		-0.1		0.0
404.0	0.0		0.0		0.0		0.0		0.0
432.0	0.0		0.0		0.0		0.0		0.0
460.0	0.1		0.1		0.1		0.0		0.1
488.0	0.1		0.1		0.1		0.1		0.1
516.0	0.1		0.1		0.1		0.1		0.1
544.0	0.1		0.1		0.1		0.1		0.1
572.0	0.1		0.1		0.1		0.2		0.1
600.0	0.1		0.1		0.1		0.2		0.2
540.3		0.09							
333.0		-0.03							
168.3		-0.41							

Fig. 4-3: Screenshot of the curve fitting spreadsheet

Source: Curve fitting spreadsheet provided by Roger Burrows

In a next step the highest and lowest reserve estimates are entered into the table and the space between these two values is partitioned into 20 equal parts for a first impression of the fitting. With these additional reserve estimates and the regression parameters NPV per BOE values are determined to define a curve for each function. Finally the functions are visualized in a chart (Fig. 4-4).

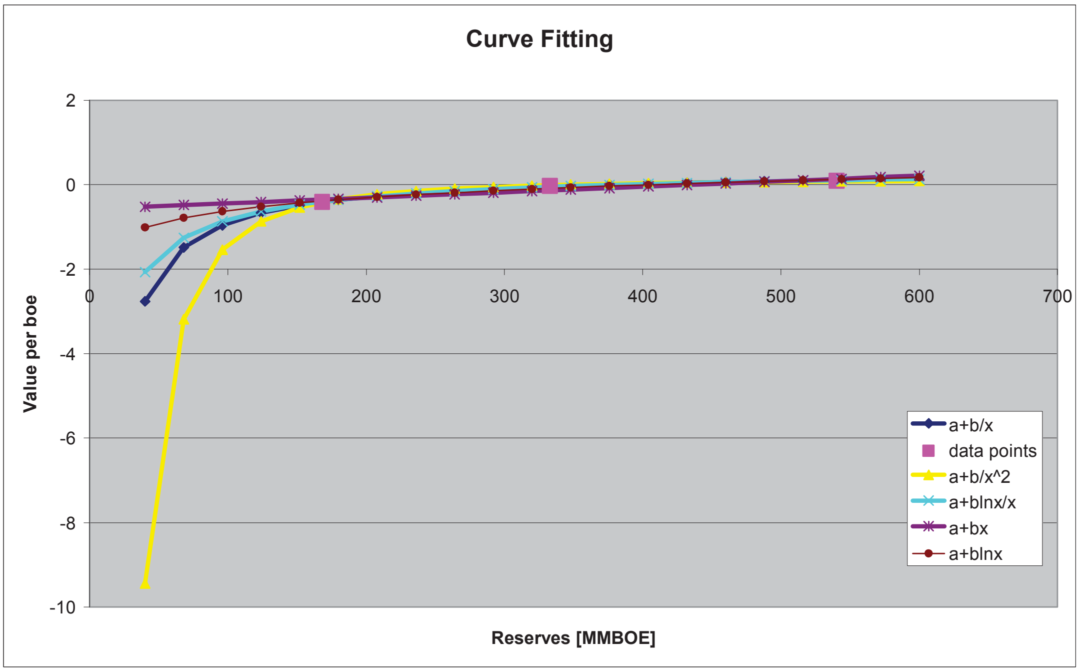


Fig. 4-4: Curve fitting with different functions

Source: Curve fitting spreadsheet provided by Roger Burrows

The best fitting function is chosen, in the upper case a+b/x, and copied into a new chart. For the determination of the most likely volume additional reserve estimates, besides the 20 estimates, can be needed at the “elbow” of the function to improve the fitting. The elbow is shown in Fig. 4-5 with the red arrow. This equals an iterative process until the elbow can be determined with some certainty and so the most likely volume of the prospect. In general, some experience is needed to find the right place of the elbow, especially when the slope of the function is very flat.

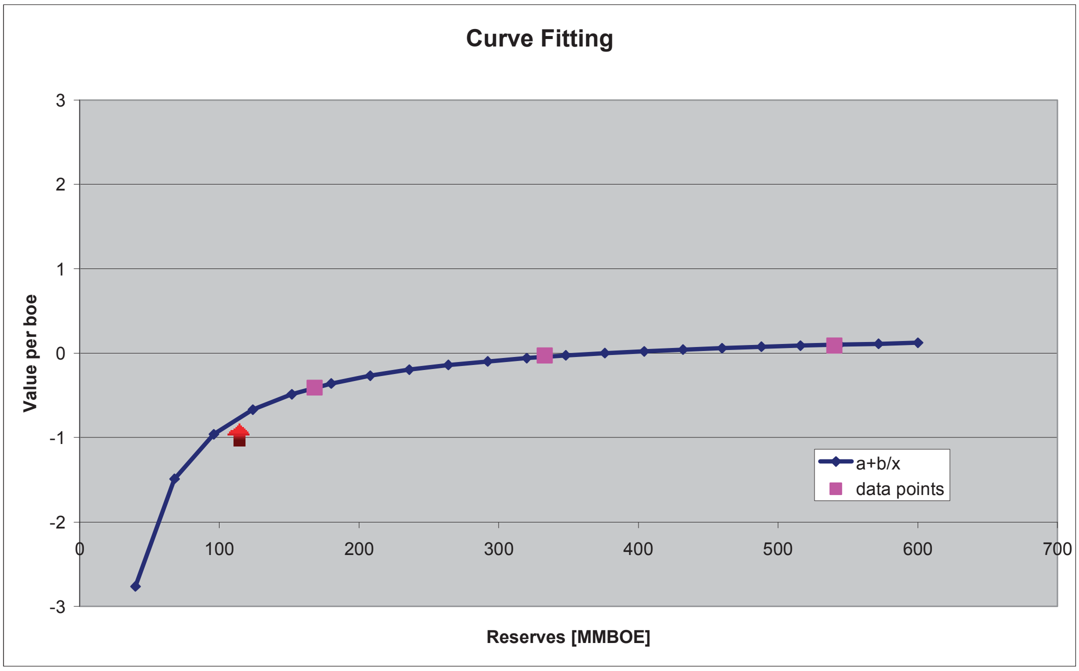


Fig. 4-5: Determination of the most likely reservoir volume

Source: Curve fitting spreadsheet provided by Roger Burrows

It can happen that the curve is too flat to determine an elbow at all. Then it is necessary to run a new case with additional input reserve values at the point where the elbow is expected to be, to confirm the analysis. The MCFS can also be determined from the graph at the point where the NPV of the graph is equal to zero.

The Petro Canada Method has the great advantage, that besides a quick determination of a MCFS and the most likely volume, the regression parameters represent the reserves, even if the P-values change due to new geological data. The old values are only additional points on the curves, whereas the new P-values can be found at different locations on the curves. Thus it is not necessary to redo the curve fitting.

Additionally Mr. Burrows mentioned three methods to determine the EMV:

- A single mean value as a “quick and dirty” method
- The Swanson rule used on a decision tree with 3 branches (P90, P50, P10)
- Monte Carlo simulation, with the advice that generally the results are slightly higher, than with the decision tree method.

4.2.2 Fletcher Challenge Energy Model

For this method firstly a prospect inventory with the following metrics available was prepared:

- A resource estimate with a commercial cutoff at the company mean product price.
- For each exploration failure, appraisal failure and P90, P50 and P10 success case a exploration case forecast, a development CAPEX forecast and in case of success an OPEX and production forecast was prepared.
- Each prospect also had a risk chance of geological success and chance of commercial success.

Additionally, a simple NPV and cash flow economic model for each country was created.

Then at least three integrated scenario models for economic parameters were developed. These include related oil price, CAPEX, operating costs and a delay or acceleration component. The basic idea is when the oil price went up the costs would increase too, because of increased rig rates due to the higher oil price.
These scenarios where incorporated into a Monte Carlo model. Each run was for a given economic assumption scenario. For each prospect the model would pick a random number from 0 to 1 and depending on the number pick the dry hole, appraisal failure or the P90, P50 and P10 case. Each case selected was run trough the economic model and the yearly CAPEX, OPEX, production rate etc. was recorded.

For related prospects the model would then select the next prospect and if the previous well result was success or failure adjust the risk accordingly. An argument to stop drilling after e.g. three consecutive dry holes can be introduced. The program then followed through the entire portfolio with a predefined number of iterations e.g. 1000. The output is the following:

- Annual cash flow at any level of risk
- CAPEX requirement per year (Exploration and development)
- Chance of creating value
- Number of dry holes
- Estimates of reserves
- Annual production rates
- Annual OPEX
- NPV
- etc.

Including an economic model and an economic scenario the Monte Carlo model has the advantage of very quickly answering questions on oil price sensitivity etc. It is also not necessary to go back to regions for economic updates.

4.3 General Studies on Economic Prospect Evaluation

In the first section of this chapter several published SPE-papers are presented which proved to be an important contribution to economic prospect evaluation. The second part gives a short insight into papers which are related to the topic of this thesis and the most important conclusions are pointed out.

4.3.1 Recommended Studies

Three papers are presented; the first gives a comprehensive overview of decision making techniques published by **Simpson et al.**[77] The second paper by **Dunn and Parnell**[78] shows a fairly simple method to determine an EMV, the method was actually used for prospect evaluation. Finally **Mudford**[79] compares decision tree and Monte Carlo simulation on a Gulf of Mexico gas field.

Simpson et al.[80] conducted interviews with the decision makers of most operating companies active in the UK. The extend to which each company uses decision analysis defines a rank order list which is then correlated with other rank lists based on common measures of business performance.
Current techniques of decision making are presented and sorted in order of increasing sophistication:[81]

- No Analysis: As there are no formal methods except experience and its sharing with others.
- Holistic View: The total effect and consequences of a decision are taken into account.
- Discounted Cash Flow Techniques: The timing of cash flows, the time value of money and decision making criteria like the NPV are used for project evaluation.

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[77] See Simpson et al. (2000)

[78] See Dunn and Parnell (2002)

[79] See Mudford (2000)

[80] Cf. Simpson et al. (2000), p. 1 et seq.

[81] Cf. Simpson et al. (2000), p. 2 et sqq.

- Risk and Uncertainty: Risk and uncertainty are incorporated into the analysis, information is bought to reduce uncertainty to acceptable levels.
- Portfolio Theory: A diversified portfolio of uncertain opportunities is preferable to an equal investment in a single opportunity. The impact of an incremental investment on the total portfolio is taken into account.
- Option Theory: Traditional discounted cash flow techniques can be modified to assign credit to an opportunity for being able to assess and to avoid the downside uncertainty involved in decision by aborting or postponing that decision until certain conditions are met.
- Preference or Utility Theory: The decision maker's attitude and feelings about money are incorporated into a quantitative decision parameter. Unfortunately is it difficult to define a utility function for a company, as the decision maker's attitude can change form day to day.
- Qualitative and Quantitative Input: Only very few decisions are based solely on quantitative analysis. Habit, instinct and intuition often overrule the results of the quantitative analysis. These qualitative inputs are systematically documented and calibrated. It would make decision making in multi-partner companies comparable.

As a result of the ranking of the companies a strong correlation between the use of decision analysis and the various measures of success is found.

Dunn and Parnell[82] published a method which is based on work published by Capen[83] and Clapp. The technique was applied several years for evaluation of exploration ventures. The process can be divided into four steps:

- Estimation of the Geologic Chance Factor (GCF): Source/migration, trap and reservoir chance factors are determined and the product of them gives the GCF.

- Estimation of the Reserves Distribution: The authors prefer a 10/90 approach, where 10% is the low side case and 90% the high side. The two points are plotted on a lognormal paper and connected by a line, which should cross the 50% probability at the "even odds point of indifference" This is done for the productive area, net pay thickness and recovery factor. For the calculation of the product of these factors either Monte Carlo simulation or statistical techniques are recommended.

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[82] Cf. Dunn and Parnell (2002), p.1 et sqq.

[83] See Capen (1992)

- Calculation of the Minimum Economic Size (MES) and Economic Chance Factor (ECF): The determination of the MES is a iterative process The present value of a reserve size is calculated, which is believed to be close to zero. If the result does not yield a zero present value, a new size is chosen, which is closer to that value. With the MES the portion of the reservoir below it is truncated. To determine the ECF, which is the chance of a commercial discovery the reserve distribution is plotted on a lognormal paper and the MES is added. A vertical line at this point gives at the intersection of the probability axis the ECF.

- Calculating the expected value: The mean of the truncated distribution is determined. According to this value, realistic values for area, net pay and recovery factor are determined. With these values production rate and development costs are estimated. Finally a two branch decision tree is created and the EMV of the mean and a dry hole case is calculated.

In addition to this technique the authors offer a list of observation made during the use of this technique in exploration venture evaluation. The method is recommended as simple enough to be used in every day business but still accounts for uncertainty of the parameters.[84]

Mudford[85] made a comparison of decision tree and simulation methodologies. In general it is stated, that probabilistic methods are frequently used to analyze likely hydrocarbon volumes, but are infrequently used in economic analysis, even though there are many uncertainties associated with engineering and economic components of an oil and gas project.

Mudford divides the probabilistic model of a Gulf of Mexico gas field into separate geosciences, engineering and economic sections. After calculation of the NPV an economic threshold has to be determined. This is done by cross plot of NPV versus recoverable volume without any economic threshold at first (Fig. 4-6). The optimum threshold is then chosen at a point to achieve the largest mean NPV.[86]

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[84] Cf. Dunn and Parnell (2002), p. 6

[85] Cf. Mudford (2000), p. 1 et seq.

[86] Cf. Mudford (2000), p. 2 et seq.

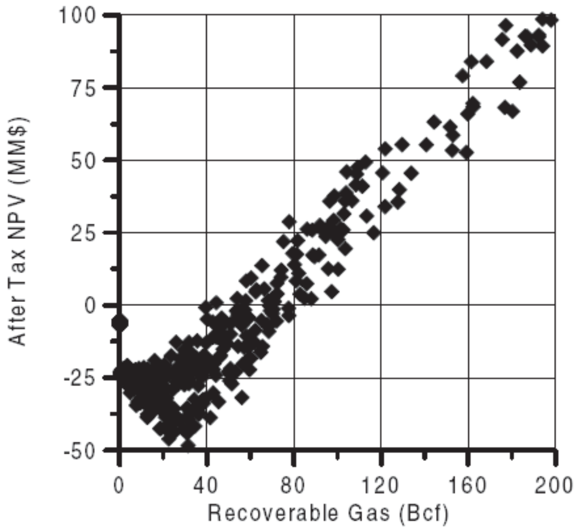

Fig. 4-6: After tax NPV versus recoverable gas

Source: Mudford (2000), p. 8

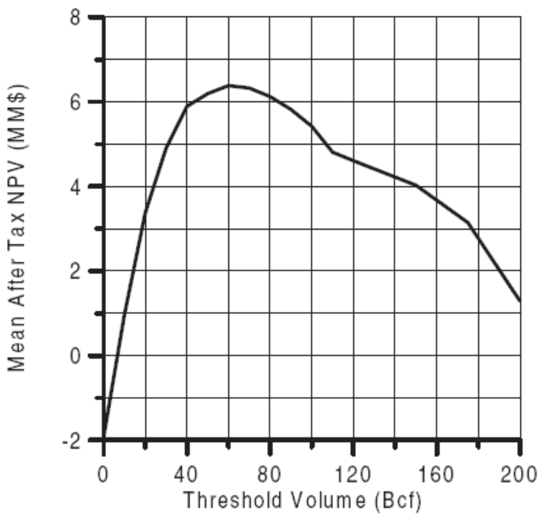

Fig. 4-7: Estimated mean after tax NPV versus threshold volume

Source: Mudford (2000), p. 8

The mean NPV is estimated by assuming that all iterations with volumes below the threshold will have an NPV equal to the mean failure NPV. Fig. 4-7 shows that in this case the threshold is less than about 40 Bcf where the mean NPV begins to drop rapidly. Therefore it is recommended to collect sufficient data to minimize the likelihood of developing a recoverable volume of less than 40 Bcf. Due to the limited amount of information the threshold volume should be selected higher than 40 Bcf, which would be around 60 Bcf. With this threshold the stochastic model is rerun, the new economic data of this prospect are then available.[87]

[87] Cf. Mudford (2000), p. 3

Four scenarios are used for the decision tree that comprises a failure and three success cases. The three success cases correspond to two-well, four-well and six-well developments equal to P90, P50 and P10 respectively of the recoverable volume distribution. The threshold volume is determined by finding a P90 volume where the NPV is zero. Now the economics can be calculated again.[88]

As a result Mudford shows that the NPV's calculated with both methods are similar, but degree of difference between the mean NPV is project specific. A four-point model can only be correct at four places; it will not provide the true downside or upside of a project. An advantage of stochastic models is that sensitivities and driver of a project can be analyzed in a consistent manner. Finally, management decisions can be analyzed as easily using stochastic models as can be done with decision tree models. The advantage of stochastic models is that the impact of engineering and development uncertainty is an integral part of decision analysis.[89]

4.3.2 Related Studies

A short insight in four papers is given; **Murtha**[90] treats the topic of Monte Carlo simulation in the first paper. **Hooper III**[91] presents a way to combine existing spreadsheet algorithms into a fully stochastic evaluation model. **Erdogan et al.**[92] compares portfolios evaluated by different methods and finally **Ball Jr. and Savage**[93] present a method to optimize portfolios with a model based on Monte Carlo simulation on linear programming.

Murtha[94] published an important paper about Monte Carlo simulation. Besides recommendations for the use of the Monte Carlo technique in prospect evaluation, insight is given into its probable future development. Further a guideline is presented for successful implementation of Monte Carlo simulation into daily exploration business.

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[88] Cf. Mudford (2000), p. 3 et seq.

[89] Cf. Mudford (2000), p. 6

[90] See Murtha (1997)

[91] See Hooper III (2001)

[92] See Erdogan et al. (2001)

[93] See Ball Jr. and Savage (1999)

[94] Cf. Murtha (1997), p. 336 et seq.

Murtha gives a warning to be careful when multiplying or adding up P-values. This can only be done with utmost care when the distributions are lognormal and not correlated[95]. Otherwise it is almost impossible to determine what the resulting P-value represents, it can be somewhere between P1 and P2 when multiplying P10 values. Mean values can be multiplied, provided there is no correlation between the input distributions. Only the adding up of means poses no problem.

Erdogan et al.[96] compared the optimization of a portfolio of stochastic evaluations with the results of optimizing a portfolio with decision tree approximations to the full stochastic models. Each portfolio was chosen from an opportunity set of 20 exploration-type projects. The results show, that project risks have to be characterized fully and robustly. As the projects risk is less robustly characterized in decision tree portfolios, the capital was used less efficient compared to simulation portfolios.

Hooper III[97] presented a paper where existing algorithms are combined into a stochastic spreadsheet model. Spreadsheets for reserve calculations, capital requirements, after federal income calculation, tax and fiscal regimes and a mean reverting price model were brought together. Much attention was devoted to the presentation of the results in a poster sized print out of input and output parameters. Thus the decision makers were able to get a visual grasp of the whole project at once.

Ball Jr. and Savage[98] published an E&P portfolio optimization model, which works by generating Monte Carlo trials representing the uncertainties of the various projects, including the interplay among projects. The trials are fed into a linear program, which finds a portfolio of minimum risk for a given expected NPV. This process is repeated for a range of desired expected NPV's, thereby determining the efficient frontier and the portfolios that make it up.

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[95] The Peter Rose Methodology uses this special case.

[96] Cf. Erdogan et al. (2001), p. 5

[97] Cf. Hooper III (2001), p. 2

[98] Cf. Ball Jr. and Savage (1999), p. 79 et seq.

5 Prerequisites for the OMV Evaluation Model

This chapter documents the process of the evaluation model development. At the beginning the actual state of OMV is described and the targets of the evaluation set. The dataset, provided by OMV, is presented. Finally a short overview is given about the actual petroleum resources classification system and definitions.

5.1 Actual State at OMV

In 2002 OMV implemented an evaluation method based on the PRM to improve consistency in evaluating risk and prospective resources. The geotechnical evaluation of an exploration project is based on two main building blocks:

- Play assessment
- Prospect evaluation

5.1.1 Play Assessment

Play assessment helps to target areas of interest and rank them into areas of common risk. The play has to be assessed prior to the prospect evaluation. It is important to revise data of plays continuously as more prospects are drilled and more data becomes available. The play mapping should be also carried out in familiar areas as in case of joining new people the knowledge transfer can be done easily.

The main benefits of continues play assessment are:

- The play mapping is the best way to summarize and represent the regional geology of a basin.
- It is the best way to summarize exploration ideas and concepts.
- It allows the identification of dependencies between prospects, which has to be considered for evaluation.
- Finally, the risk is reduced to overlook problems like gaps in the knowledge, or additional unknown risks of plays.

5.1.2 Prospect Evaluation

The evaluation of prospects is the final objective of most exploration studies as this value creating act is an important contribution to the value of an oil company. To preserve a consistency in the evaluation prospects are collected in the Prospect Inventory (PI). This inventory is a technical document which includes geological, geophysical, engineering and economic data. It is the base for establishing the exploration strategy.

The data is collected from the different regions in the world into one PI, where the projects are divided into appraisal, exploration and mature wells. As it lies in the nature of petroleum business that at early stages of exploration the data has the highest uncertainty a thorough risk assessment is necessary. Through the exploration portfolio management process the PI is optimized in order to maximize its value and achieve the company targets.

The next step is the calculation of economic indicators like NPV or EMV to receive a value of the prospect and in the course of it a value for the prospect inventory. The results are presented in meetings and the decision is made according to the actual company strategy and exploration budget (Fig. 5-1).

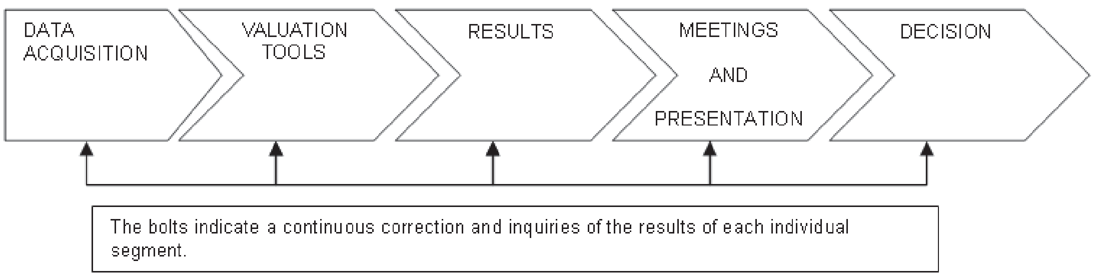

Fig. 5-1: OMV Decision Flow

Source: Secklehner (2006), p. 54

As it is time consuming to do a detailed economic evaluation of every prospect OMV is interested in a procedure to quickly determine an indicative value of a prospect to sort out currently unattractive prospects and focus the attention on more promising investments.

5.2 Objectives of the Evaluation

A meeting was held to give the main points of the practical part of the thesis. The evaluation should be done on a series of prospects and the necessary data would be provided by OMV.

An agreement was made to look into three available methods to derive a prospect value:

- The use of mean values only.
- Four branch decision trees with P10/P50/P90 values and a dry hole case, the mean value calculated by the Swanson mean.
- A fully probabilistic Monte Carlo simulation.

All these methods can be used to determine an expected value of a prospect. The geologic input parameters often have an uncertainty of more than 50% of the estimated values. Therefore, the target is to determine whether it is necessary to use methods with higher sophistication like decision trees and Monte Carlo simulation or if a simple mean value calculation is sufficient as an approximation.

Further, a special interest is the influence of different oil price scenarios on the result. These scenarios are:

- Mean oil price
- A high and a low oil price scenario
- Full distribution of the oil price

In addition the usefulness of NPV versus reservoir volume charts also called Value per Barrel (VPB) curves should be pointed out.
Finally the Petro Canada method of curve fitting will be investigated on accuracy for determination of the MCFS.

5.3 The Dataset

As the focus lies in economic evaluation, a dataset of geologic input data was provided by OMV (Tab. 5-1). The list contains 10 oil and gas prospects, seven of them onshore, three offshore. The reserves are given as total reserves, as oil and gas volumes were added up to Barrels of Oil Equivalent (BOE). Pg, gross dry hole costs and the initial production per well are also given.

As for Prospect 6 to 9 the P50 value was missing, it was determined by the distribution constructed out of P90, P10 and mean value. The procedure will be explained later in more detail. Because of obvious similarities, like being onshore oil prospects with similar dry hole costs, for Prospects 6 to 9 the assumption is made that they belong to a play.

Running Number	Onshore/ Offshore	HC Type	Total Reserves [MMBOE]				Chance of Geological Success Pg	Gross Dry Hole Cost [MMUSD]	Initial Production per Well [boe/day]
			P90	P50	P10	Mean			
Prospect 1	Offshore	Oil	2.00	8.00	46.00	18.00	31%	6.00	1000
Prospect 2	Onshore	Gas	0.08	0.89	6.39	2.36	28%	10.00	2500
Prospect 3	Offshore	Gas	4.14	10.80	28.20	13.76	57%	10.00	1800
Prospect 4	Onshore	Gas	3.65	8.11	18.00	9.60	68%	8.00	2200
Prospect 5	Offshore	Oil&Gas	2.00	3.50	5.20	3.60	100%	12.00	500
Prospect 6	Onshore	Oil	7.00	*21.60*	99.00	42.00	60%	2.40	1250
Prospect 7	Onshore	Oil	1.00	*11.20*	48.00	18.00	11%	2.50	3500
Prospect 8	Onshore	Oil	1.00	*8.19*	31.00	12.00	9%	4.00	2100
Prospect 9	Onshore	Oil	1.00	*5.43*	18.00	7.00	19%	3.00	500
Prospect 10	Onshore	Gas	7.17	27.17	101.67	42.83	43%	5.00	1400

Tab. 5-1: Dataset of prospects used for the evaluation

Source: OMV

5.4 SPE – WPC – AAPG Petroleum Resource Classification System and Definitions

The OMV uses the resource definition of January 2000 approved by the Society of Petroleum Engineers (SPE), the World Petroleum Congress (WPC) and the American Association of Petroleum Geologists (AAPG), which is a supplement to the existing “SPE/WPC Petroleum Reserves Definitions” (1997) and did not modify those definitions in any way. The two sets of definitions should be viewed as companion documents. These definitions represent a major step to improve consistency in reserves estimation end reporting on a worldwide basis.

The resource classification system is summarized in Fig. 5-2 where the recoverable portions are defined separately as Reserves, Contingent Resources and Prospective Resources.[99]

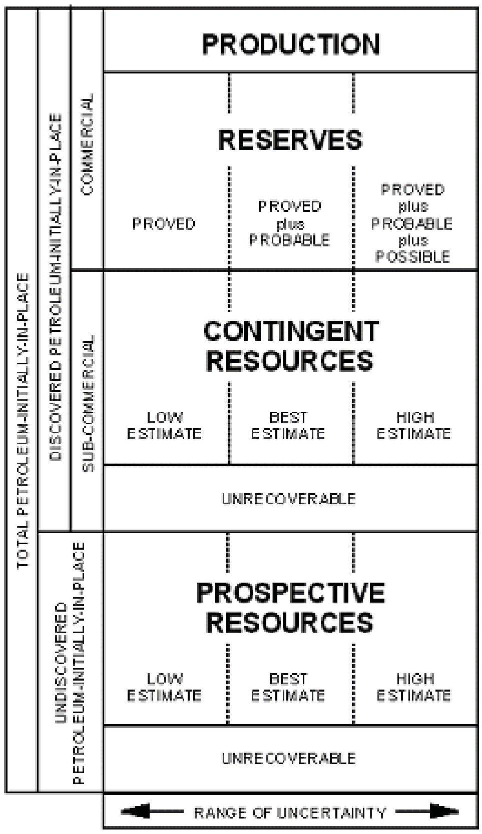

Fig. 5-2: Resources Classification System

Source: SPE: http://www.spe.org/spe/jsp/basic/0,,1104_12171,00.html

Reserves are defined as those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. Reserves are subdivided into Proved, Probable and Possible Reserves (Fig. 5-3):[100]

- Proved Reserves are those quantities of petroleum which, by analysis of geological engineering data can be estimated with reasonable certainty to be commercially recoverable from a given date forward, from known reservoirs and under current economic conditions, operating methods and government regulations. There should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

[99] Cf. SPE Petroleum Resources Classification System and Definitions: http://www.spe.org/spe/jsp/basic/0,,1104_12171,00.html

[100] Cf. SPE Petroleum Reserve Definitions: http://www.spe.org/spe/jsp/basic/0,2396,1104_12169_0,00.html

- Probable Reserves are unproved reserves which analysis of geological and engineering data suggest are more likely than not to be recoverable. In this context, at least a 50% probability that the quantities actually recovered equal or exceed the sum of estimated proved plus probable reserves.
- Possible Reserves are unproved reserves which are less likely to be recoverable than probable reserves. There should be at least a 10% probability that the quantities actually recovered equal or exceed the sum of estimated proved plus probable plus possible reserves

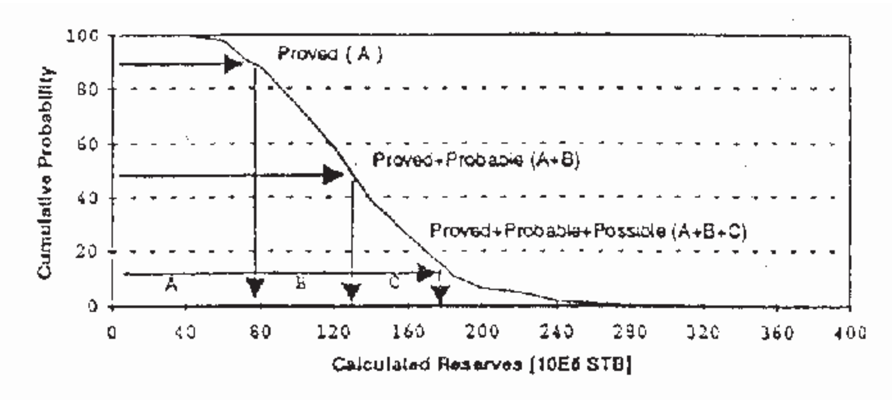

Fig. 5-3: Example probability distribution of reserves
Source: Ruthammer (2003)

Contingent Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are currently not considered to be commercially recoverable.

Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

6 Evaluation Model Development

This chapter describes the process of the evaluation spreadsheet development as well as the assumptions made therefore. As the spreadsheet is divided into two sections they will be presented accordingly, firstly a production forecasting is done, followed by the economic calculations.

6.1 Production Forecasting

To determine an indicative value like NPV or EMV for each of the given prospects it was necessary to develop a production forecasting spreadsheet (Fig. 6-1). The model had to be simple due to the limited amount of time available but also suitable to fulfill the objectives like evaluating deterministic models with mean values or four-point decision trees as well as Monte Carlo simulations. For the latter, the Excel add-in @Risk from Palisade Corporation proved to be preferable due to the easy implementation of the given reserve distributions and the possibility to create out of the reporting data VPB curves.

Production Forecasting

Input:

Total Reserves	18	MMBOE
Initial Well Production	1000	BOE/d

Adjusted Initial Well Production	1040.00	BOE/d
Peak Productivity	12.7	% of Reserves p. a.
Decline Rate	12.7	% of Well Production
Cutoff	3	% of Initial Rate
Max.Theoretical Production	2283.1	MBOE/year

Drilling Time per Well	15	days	Number of Wells per Year	20.0
Drilling Time per Year	300	days	Actual Wells	5

Fig. 6-1: Screenshot of the production forecasting spreadsheet

6.1.1 Defining the Reserve Distributions

The first step was to adjust the available reserve data for the evaluation. As the mean reserves were given, no more efforts had to be spent on this method.

For the stochastic calculations with Monte Carlo simulation probabilistic distributions were defined as follows:

The P90/P50/P10 values were used to define the shape of the lognormal distribution. To adjust the distributions for the given mean value, they had to be truncated. At the low side it was only possible to introduce a truncation at zero, as no geologic data were available to try a P99 guess. At the high side the truncation was made iteratively to get as close as possible to the actual mean value.

An example of the @Risk reserve distribution of Prospect 1:[101]

=RiskLognormAlt(10%; 2; 50%; 8; 90%; 46; RiskTruncate(0; 250))

As already mentioned for Prospect 6 to nine no P50 values were available, therefore these distributions were defined by the P90, P10 and the mean value. The truncation was done in similar extends as with the other prospects. Finally a P50 value was determined manually from the distribution.

For the four branch decision tree model, the spreadsheet would have needed an extension, to calculate out of three individually calculated NPV’s for each of the P-values a mean NPV according to Swanson’s rule. For simplification the simulation add-in was used to do this work. A discrete reserve distribution was created for each prospect:

Again Prospect 1 as example, where the last part is the probability of occurrence of the reserve values:

=RiskDiscrete({2.8.46}; {3.4.3})

The discrete values have a probability of occurrence of 30% of P90, 40% of P50 and 30% of P10 according to Swanson’s rule. With the introduction of the discrete distribution it was not necessary to calculate the Swanson mean manually or to adapt the spreadsheet.

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[101] @Risk uses the percentiles in the “normal” way, e.g. P10 corresponds to the 90% value.

6.1.2 Equations and Assumptions

In the following part the equations and assumptions framed for the input parameters are presented.

Initial Well Production

In a first try the initial well production was used as a constant, but this led to the problem, that large fields had relatively low production rates and in the course of those low cash flows. To overcome this problem, a relationship between the reserve size and the production rate was introduced, which was based on the assumption that the increase in hydrocarbon production comes along with improved drilling and completion technology like the possibility of long horizontal wells. For the type of relationship different functions were tried, but a simple linear function proved to be the best solution (Fig. 6-2).

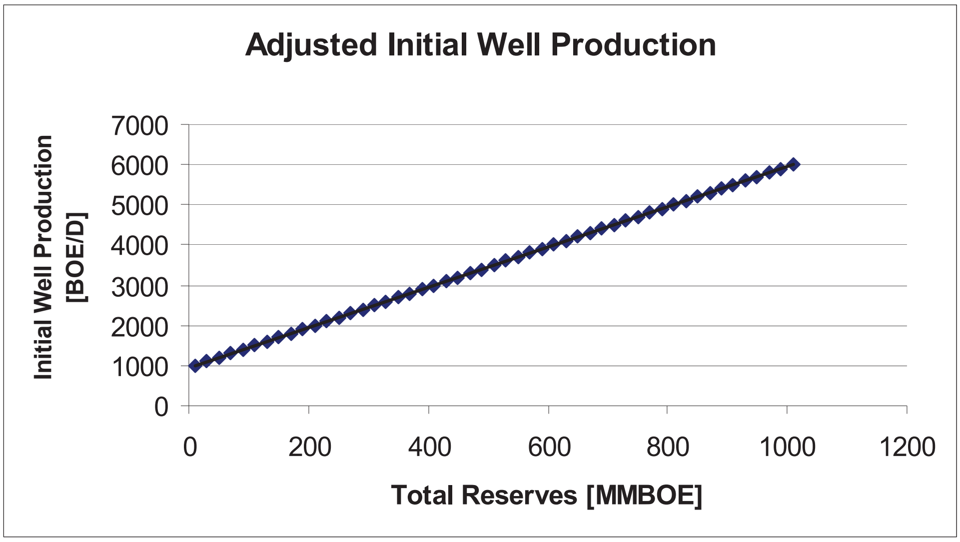

Fig. 6-2: Adjusted initial well production

For each reserve size an adjusted initial well production was calculated based on the given initial well production:[102]

Adjusted Well Production = 5 *Total Reserves + (Initial Well Production - 50)

[102] The term (-50) is used as correction term for the initial well production.

Peak Productivity

For the determination of the peak productivity real data of 22 oil and gas fields was available. As gas fields have different peak productivities than oil fields[103], a mean value had to be found due to the calculation in BOE.

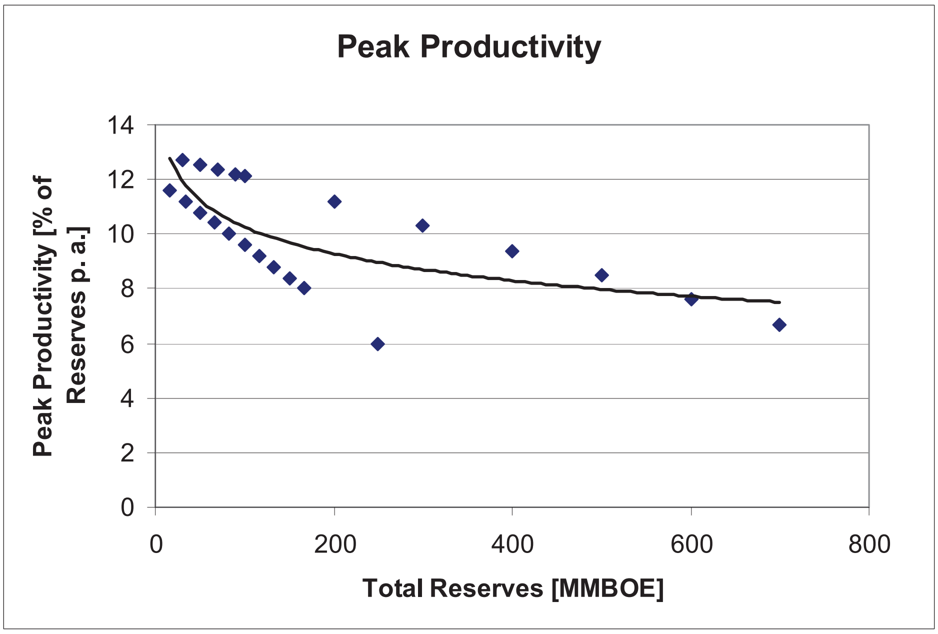

Fig. 6-3 Peak productivity

A logarithmic function fitted the data best (Fig. 6-3), especially between one and 200 MMBOE where most of the prospects reserves were distributed.

Decline Rate

The decline rate was assumed to be equal to the peak productivity to account for an exponential decline. This assumption was based on a rule of thumb by IHS Energy[104], who compared the data of many wells around the world.

Cutoff

According to Lechner[105], typical values of cutoff rates range between 5 and 7% of the initial production rate. In a first try the cutoff was set at 5%, but due to the set of relatively small

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[103] Gas fields normally have longer field plateau rates to satisfy customer needs such as sales contracts.

[104] Rule of thumb from the Help-Section of the evaluation program A$SET 3.3 of IHS Energy

[105] Cf. Lechner (2003), p. 19

prospects, the cutoff often occurred after a few years only. Therefore it was reset to 3% to enlarge the production time.

Number of Wells

A maximum of 20 new well per year was set. This number proved to be suitable even for large reserves. With a lower number of wells and therefore slower starting production, the higher cash flows would have been generated in later years and due to the discounting, larger prospects would have had worse NPV's compared to smaller ones.
To calculate the actual needed number of wells, 80% of the maximum theoretical production, peak productivity multiplied by the reserves, was used. So a production plateau could be achieved. By dividing the resulting production per year with the calculated well production, the number of wells was found and rounded up to the next complete well.
When the number of the actually needed wells exceeded 20, again a maximum of 20 wells could be drilled in the following year and so on.

Production Forecasting Chart

The model was based on three stages: in year one exploration well was drilled, then three years were used to install the facilities and in the fifth year the production was started. The forecast was made for a maximum of 25 years unless the cutoff rate was reached before (Fig. 6-4). The spreadsheet calculations can be seen in the Appendix. The production data was saved in a table for further use in the economic calculations.

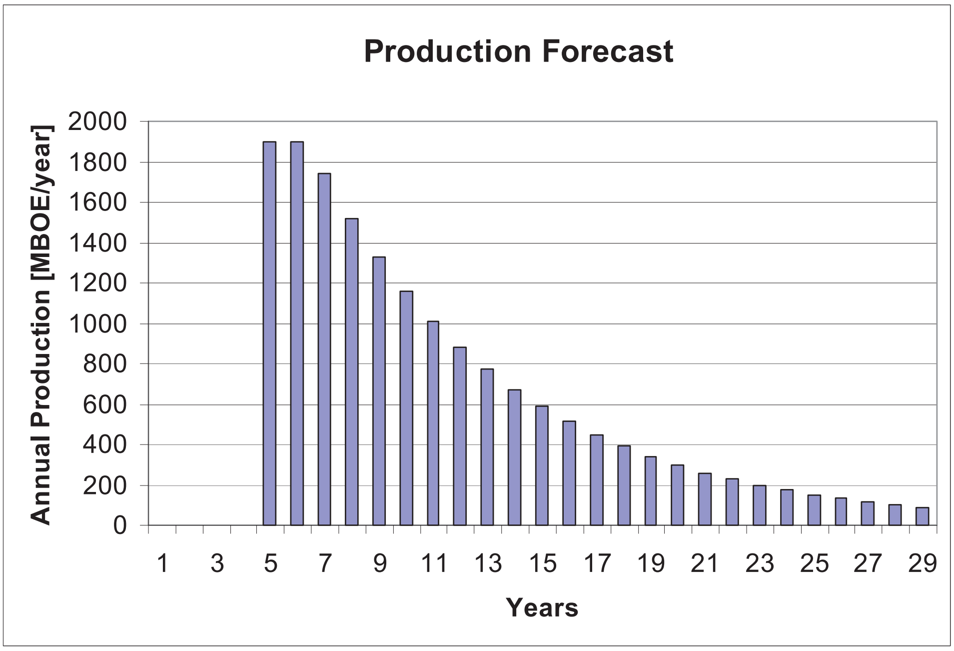

Fig. 6-4: Production forecast

6.2 Economic Model

With the production forecast it was now possible to calculate cash flows for each year. These cash flows were discounted and summed up to determine a NPV (Fig. 6-5). With the incorporation of the risk parameter Pg the EMV was calculated.

ECONOMICS

Input:

Oil Price	35.00	USD
Dry Hole Cost	5.0	MMUSD
Pg	43	%
Hurdle Rate	15	%
Royalties	15	%
OPEX	5.0	USD/BOE

Facility Cost	33.6	MMUSD
Completed Well Cost	6.8	MMUSD

Results:

NPV	69.77
EMV	27.15

Fig. 6-5: Screenshot of the economic input spreadsheet

Oil Price

A detailed analysis of the historical oil prices or future oil price models was put aside, as this kind of detailed information was not needed for the evaluation. For the evaluation it was necessary to determine a probability distribution of the oil price to account for the different oil price scenarios:

=RiskLognormAlt(10%; 20; 50%; 30; 90%; 60; RiskTruncate(0; 114.5))

The procedure was similar to the reserve distributions. First a lognormal distribution was formulated by a P90 of 20 USD, a P50 of 30 USD and a P10 of 60 USD. To receive a mean oil price of 35 USD the high side of the distribution was truncated at 114.5 USD.
With this distribution it was possible to use consistent set of values; the P90 value was used as a low oil price scenario, the P10 value as a high oil price scenario accordingly. Also the mean oil price was given by the distribution.

Dry Hole Cost and Pg

In general a dry hole is a wellbore that has not encountered hydrocarbons in economically producible quantities. When a well becomes economically interesting depends on many factors like proximity to transport and processing infrastructures, local market conditions, expected completion costs, tax and investment recovery conditions of the jurisdiction and projected oil and gas prices during the productive life of the well.[106]
The Pg was used according to the PRM and shows only the technical chance of finding an accumulation capable of sustained flow to the surface.

Both values were given in the dataset provided by OMV.

Completed Well Cost

The completed well costs were determined based on a linear equation with the reserves as variable and the dry hole cost as a constant (Fig. 6-6). The assumptions behind the equation were that a completed well would be 20% more expensive than a dry hole. Further, based on the higher well production rate of larger fields due to improved technology and higher cost for infrastructure, the well cost would be higher accordingly.

Completed Well Costs = 0.1 * Reserves + ((1.2 * Dry Hole Cost)-1)

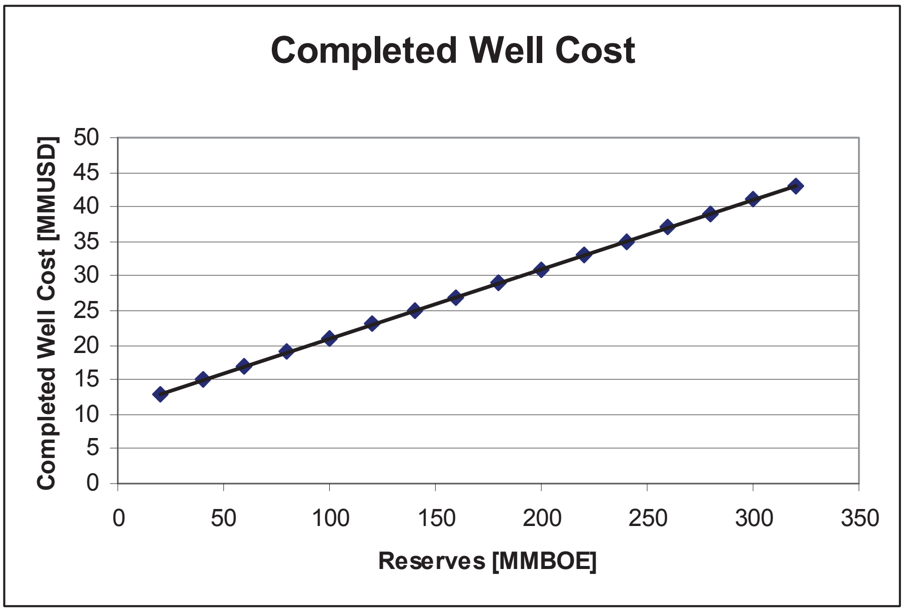

Fig. 6-6: Example calculation based on dry hole cost of 10 MMUSD

[106] Schlumberger Oilfield Glossary: http://www.glossary.oilfield.slb.com/Display.cfm?Term=dry%20hole

Hurdle Rate

As hurdle rate 15% were assumed and it was used in this evaluation only to express the time value of money needed for the NPV calculation.

Royalties

Royalties are a percentage share of the production or the production revenue paid from a producing well to the lease owner or the state. The owner of this share of production does not bear any of the cost of exploration, drilling, producing, operating, marketing or any other expense associated with drilling and producing an oil and gas well.[107] For the purpose of this evaluation royalties of 15% were assumed.

OPEX

OPEX are costs a company must pay in order to maintain business, like the maintenance of the production facilities. OPEX can be divided into fixed and variable cost, whereas the latter can change with the grade of activity, fixed cost stay the same.
For the evaluation OPEX of different regions were available. As these values had a large range form about 1 USD/BOE to over 15 USD/BOE, depending on the region, a mean value of 5 USD/BOE was chosen. To keep the results of the evaluation comparable no difference was made between onshore and offshore prospects.

CAPEX

CAPEX are used by a company to acquire or upgrade physical assets such as property, industrial buildings or equipment[108]. In upstream petroleum business CAPEX mainly consist of exploration, development and abandonment cost. Companies must invest heavily in exploration to discover new sources of crude reserves in addition many of these new supplies lie in environmentally challenging surroundings like deep water or arctic areas.

According to the three stages of the production forecasting model in the year one an exploration well was drilled, the cost of such a well were assumed to be the cost of an completed well due to the higher drilling risk in unknown areas.

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[107] Schlumberger Oilfield Glossary:
http://www.glossary.oilfield.slb.com/Display.cfm?Term=royalty%20interest

[108] Investopedia: http://www.investopedia.com/terms/c/capitalexpenditure.asp

The development costs were divided into facility cost and completed well cost. The facility costs were divided over three years (year 2 to 4) with 20% of the amount in the first year and 40% each in the following two years. The completed well cost accrued in the year when the well was drilled. The determination of the facility cost was based on real data of seven prospects of different reserve sizes (Fig. 6-7). A polynomial trend line had the highest coefficient of determination and was used for the evaluation:

Facility Cost = -0.00006 * Total Reserves^2 + 0.8393 * Total Reserves + 18.494

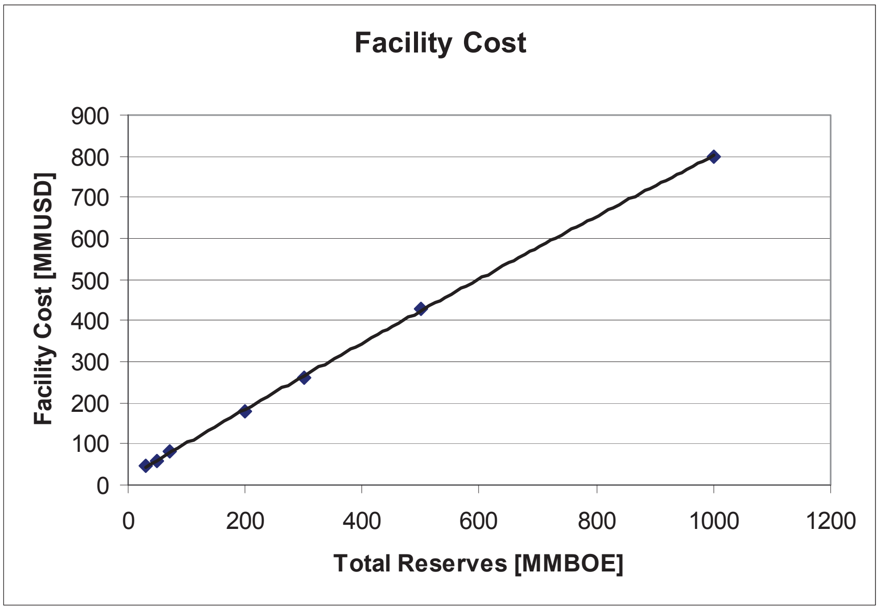

Fig. 6-7: Facility cost based on real data

For the evaluation model abandonment costs were neglected. The costs would have been very small due to the discounting over a long period on the one hand and difficult to predict on the other hand, because of probably changing regulations for abandonment of facilities in the future.

Determination of NPV and EMV

The cash flows were calculated by multiplying the produced reserves by the oil price. From this gross value OPEX, royalties and well cost were subtracted. In the next step the NPV was calculated with the hurdle rate as discount rate (Fig 6-8). With the dry hole costs and Pg the EMV's of the prospects were determined. A screenshot of the spreadsheet calculations can be seen in the Appendix.

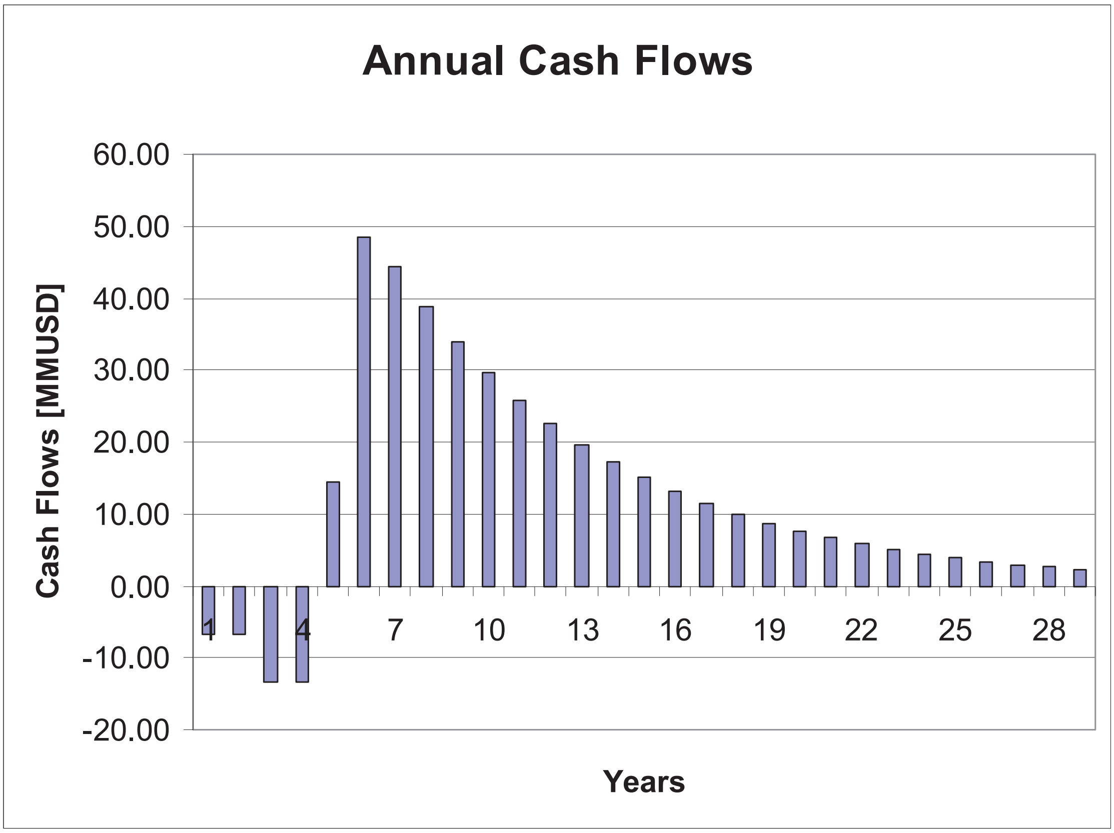

Fig. 6-8: Annual cash flows

7 Evaluation Results

With the realization of the spreadsheet model the evaluation could be started. The first task was the analysis of the three evaluation methods and oil price scenarios.
In the course of this analysis several opportunities occurred to combine the available data into a set of quick look methods and additional ranking factors for the portfolio analysis. The most promising results are present in the following chapter. Finally the Petro Canada method of curve fitting was tried out for the determination of a MCFS.

7.1 Comparison of Mean Value, Decision Tree and Monte Carlo Simulation

The three methods were compared with the resulting mean NPV's and EMV's. Therefore the predefined probability distribution of each prospect was entered into the spreadsheet. For the simulation run 1000 trials were preset for the entire evaluation. The resulting values were collected into a table (Tab. 7-1). This procedure was repeated with the discrete distribution to calculate the economic measures according to Swanson's rule.
Finally the mean value of the reserves was used for the calculation. During this evaluation the oil price was kept constant at 35 USD which represents the mean value of the oil price distribution.

	NPV [MMUSD]		
	Mean	Swanson Mean	Monte Carlo
Prospect 1	65.75	59.21	58.31
Prospect 2	-11.03	-11.98	-12.03
Prospect 3	44.77	44.21	43.49
Prospect 4	31.55	31.44	31.16
Prospect 5	-20.48	-20.78	-20.81
Prospect 6	190.56	170.25	170.33
Prospect 7	91.44	91.22	84.62
Prospect 8	53.69	53.44	49.72
Prospect 9	21.30	23.60	19.58
Prospect 10	179.33	172.13	167.86

Tab. 7-1: Mean value, Swanson Mean and Monte Carlo results

NPV's seemed more suitable for the comparison, as the EMV is only a risk weighted recalculation of the NPV with the constants Pg and the dry hole cost of each prospect. Monte

Carlo simulation was assumed to be the reference method due to the highest level of sophistication. The following chart (Fig. 7-1) shows a comparison of the three methods:

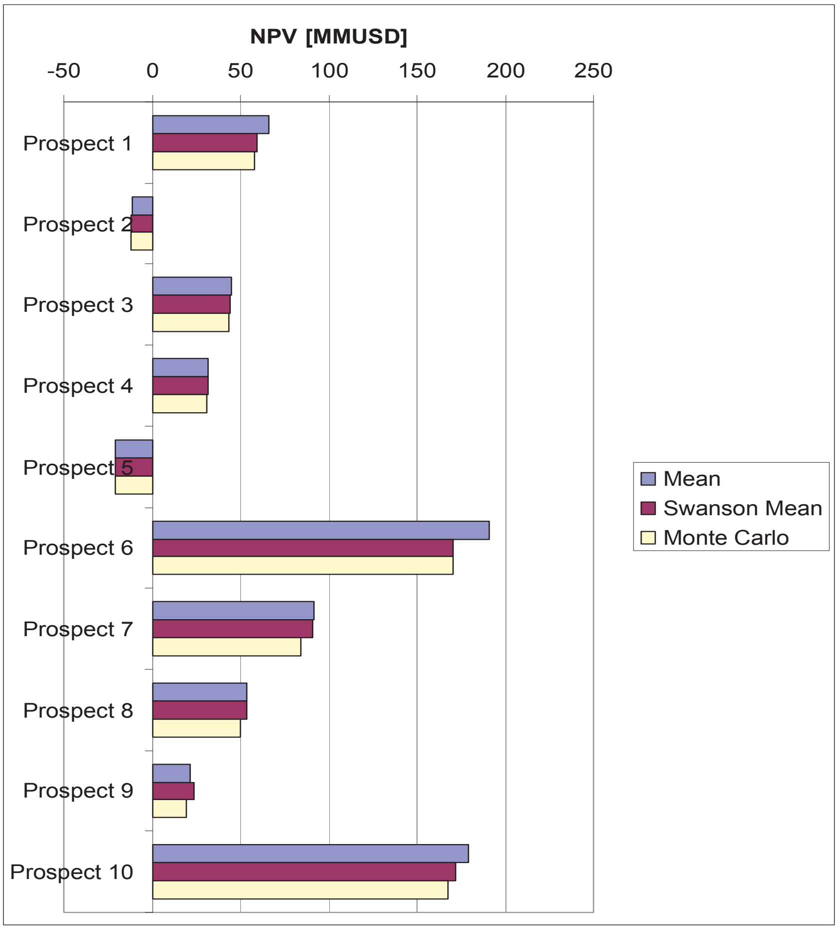

Fig. 7-1: Comparison of three methods

The results have a total deviation from the Monte Carlo simulation of

- 3.5% with the Swanson Mean
- 9.2% with a single mean value.

This shows that there is actually only a small deviation between these methods, especially in comparison to the uncertainty of the input parameters. Therefore a recommendation is made to calculate the economic measures with mean values first, to receive an indicative value of the prospect and to apply the more sophisticated methods for a detailed evaluation of the prospects of interest.

As the comparison was made with only 10 prospects still some uncertainty of the results can be expected.

7.2 Oil Price Scenarios

The idea behind the different oil price scenarios is to remove prospects from the portfolio, when they are uneconomic even with a high oil price. For the calculation of the NPV probabilistic reserve distributions were used. The before calculated NPV values with a mean oil price of 35 USD could be reused for this analysis.

High and Low Oil Price Scenario

The focus was on the determination of a high and low oil price scenario. The P10 and P90 of the oil price distribution were used for this purpose. For each of the ten prospects a NPV was calculated with the two additional oil prices (Tab. 7-2).

	NPV [MMUSD]		
	20 USD	35 USD	60 USD
Prospect 1	3.49	58.31	149.86
Prospect 2	-20.56	-12.03	2.19
Prospect 3	-1.50	43.49	118.49
Prospect 4	-1.36	31.16	85.19
Prospect 5	-33.49	-20.81	0.31
Prospect 6	48.69	170.33	371.72
Prospect 7	25.58	84.62	179.83
Prospect 8	10.53	49.72	114.96
Prospect 9	-3.64	19.58	58.27
Prospect 10	43.09	167.86	376.49

Tab. 7-2: Low, mean and high oil price scenario results

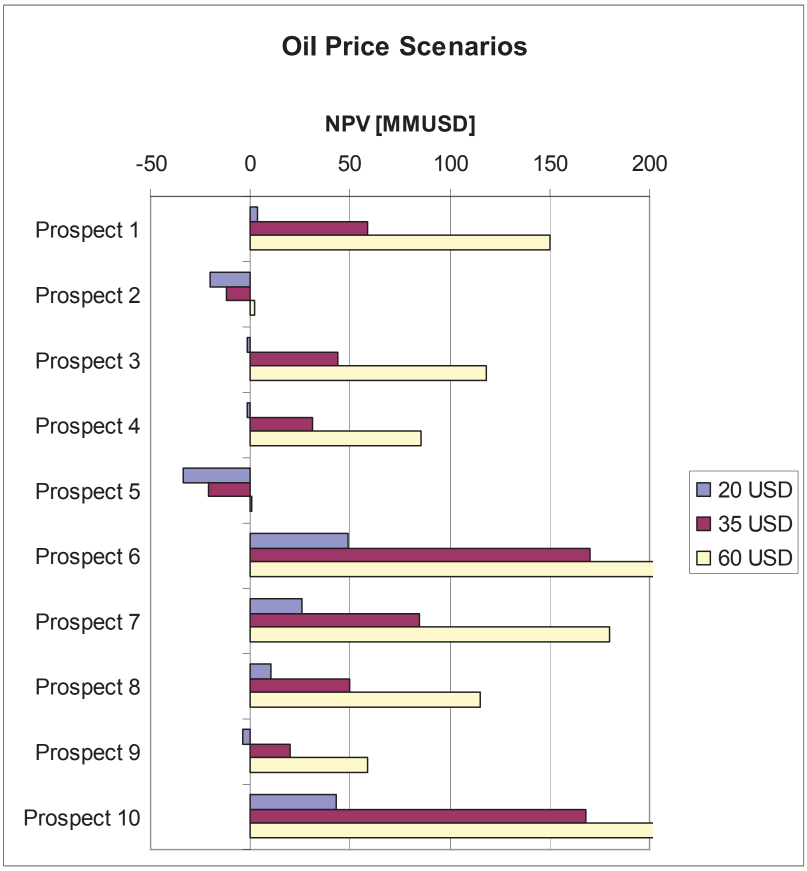

Fig. 7-2: A high and low oil price scenario compared with the mean oil price

The resulting chart (Fig. 7-2) shows that prospects like Prospect 2 and 5 have negative or only very low positive NPV and proves them to be uneconomic prospects independent of the oil price. Prospect 6 and 10 are the opposite of them and are still economic, even with a relatively low oil price. The chart gives also a good indication of the sensitivity of the prospects to decreasing oil prices (e.g. Prospect 1).

As a result it can be said that the high and low oil price scenario give a better insight into a prospect, but there is some doubt that the additional effort is worth the information as the NPV's calculated with the mean oil price already give a good indication of an economic value of a prospect.

Full Distribution of the Oil Price

A further interest was in the use of a full probability distribution of the oil price. As already mentioned a lognormal distribution was used for this purpose.

	NPV [MMUSD]	
	Mean Value	Full Distribution
Prospect 1	58.31	55.08
Prospect 2	-12.03	-12.08
Prospect 3	43.49	43.68
Prospect 4	31.16	31.76
Prospect 5	-20.81	-20.63
Prospect 6	170.33	166.91
Prospect 7	84.62	86.74
Prospect 8	49.72	48.83
Prospect 9	19.58	19.42
Prospect 10	167.86	161.83

Tab. 7-3: NPV calculated with a mean oil price and with a full distribution

It can be seen that there is only a small difference between the two oil price scenarios (Tab. 7-3). The total deviation between the two approaches is 1.8%. Nevertheless, the incorporation of a probability distributed oil price may improve the accuracy of prediction and is therefore recommended.

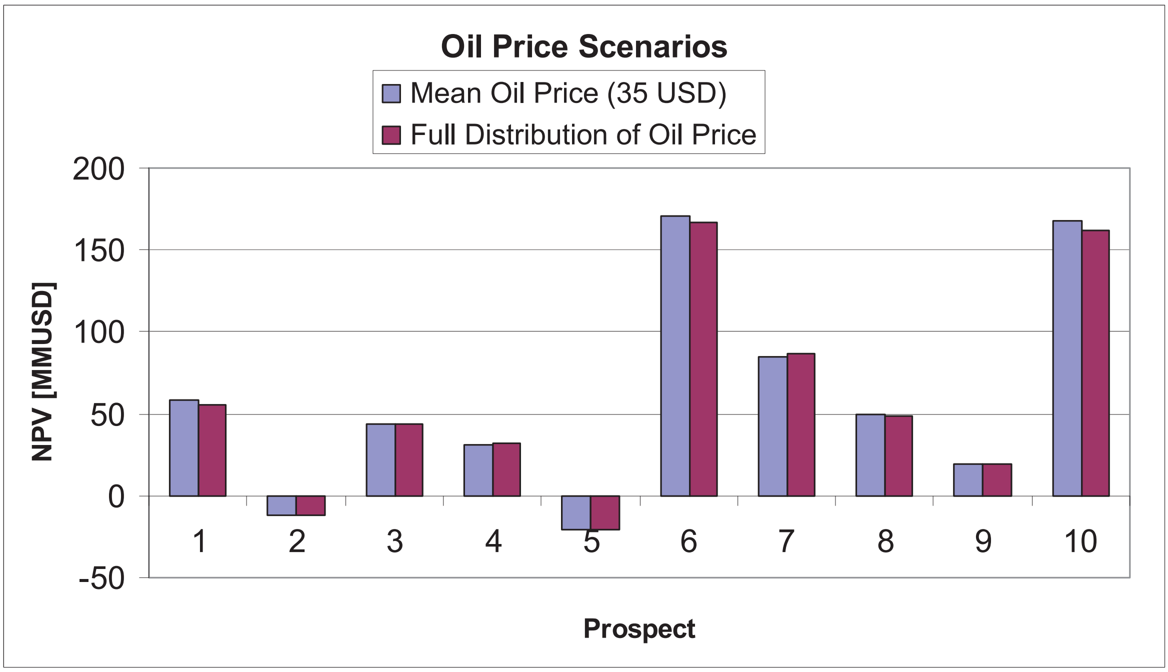

Fig. 7-3: Comparison of NPV's calculated with two oil price scenarios

7.3 Analysis of VPB Curves

As already mentioned in a VPB curve the NPV is plotted against the reserve size. To determine a VPB curve at least three data points are needed. Therefore either the P90/P50/P10 values (Fig. 7-4) of a reserve distribution can be used or the probabilistic distribution (Fig. 7-5), which provides after running the simulation as many data points as trials were simulated. Both scenarios were applied on Prospect 1 with a mean oil price of 35 USD:

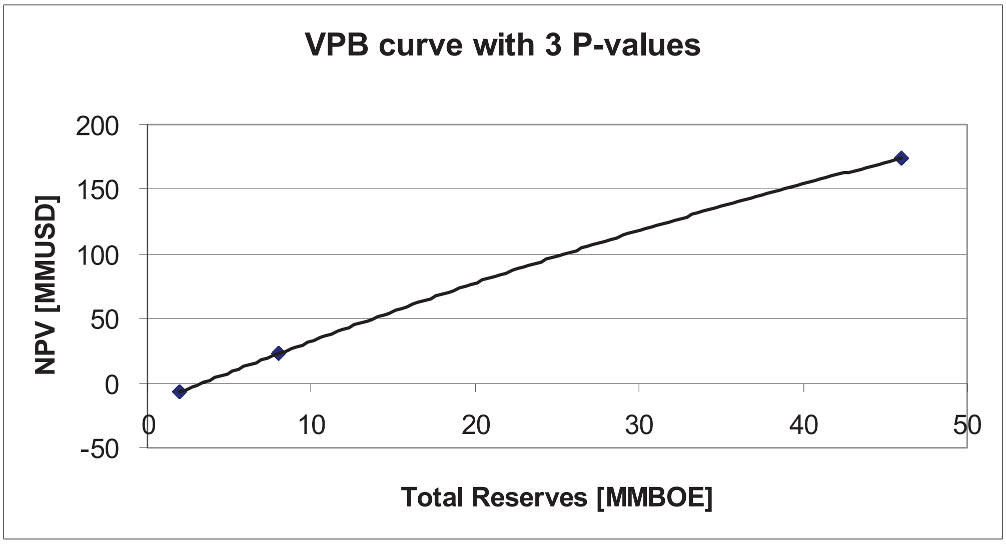

Fig. 7-4: VPB curve determined with the P90/P50/P10 reserves of Prospect 1

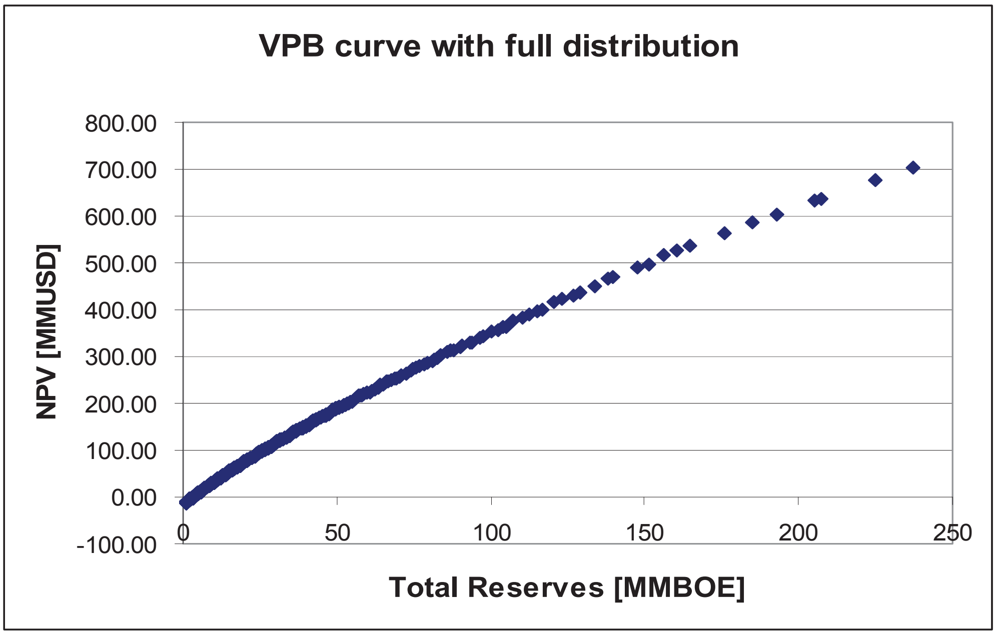

Fig. 7-5: VPB of Prospect 1 with 1000 data points

The VPB curve determined with the results of a Monte Carlo simulation obviously consists of more data points than with the three P-values. In general some of the data points of the Monte Carlo simulation have a negative NPV. This has the advantage that the MCFS can be determined by interpolation of the points. By determination of the MCFS with the three P-values, it can happen than none of these points have a negative NPV and the MCFS has to be determined by extrapolation, which is a less precise method compared to interpolation. Therefore the Monte Carlo method should be preferred. In addition, the wider range of values gives a better impression of the analyzed prospect.

Further a simulation run was made with probability distributions of the reserves and oil price (Fig. 7-6):

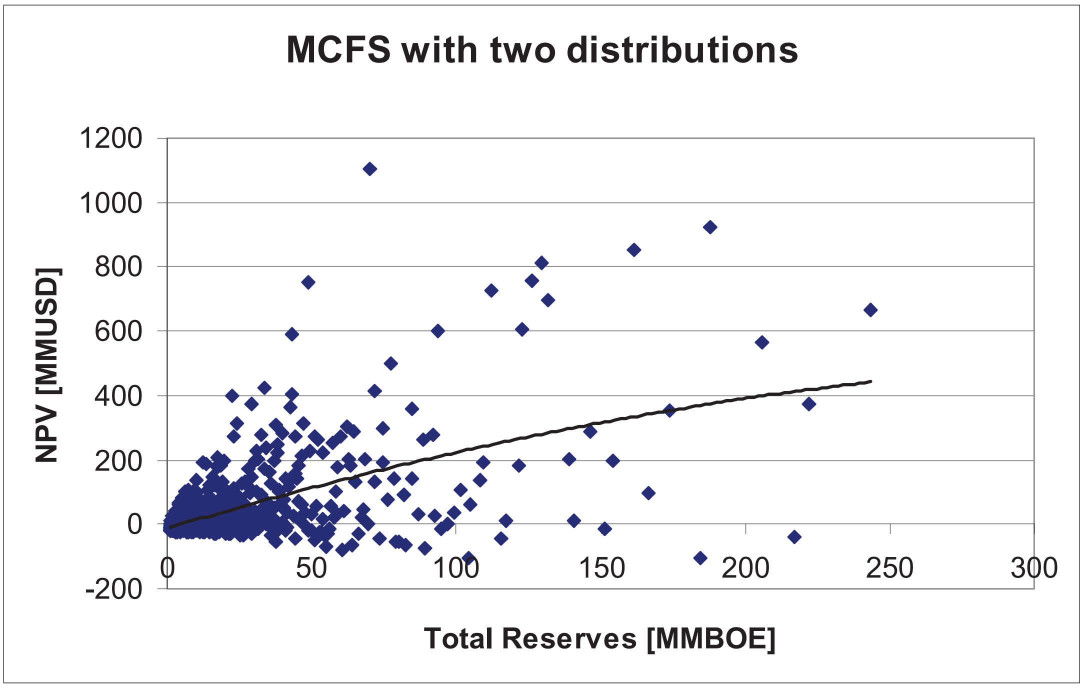

Fig. 7-6: VPB curve of Prospect 1 with two probability distributions

The combination of two uncorrelated distributions results in wide spread point cloud. Only with the approximation of a trend line a MCFS could be determined. A further analysis of the prospect is difficult, as besides the trend that a high oil price results in higher a NPV, no other specific information can be drawn from the chart. Therefore it is not recommended to use a full distribution of the oil price for the determination of a MCFS.

Comparison of methods to determine a MCFS

Two ways to determine the MCFS were investigated. Firstly with the P90, P50 and P10 values, then with the full distribution of the reserves. Again a mean oil price of 35 USD was used. To receive a comparable value of the MCFS in either case a trend line was laid over the VPB curves. This trend line was optimized to a maximum of the coefficient of determination. In most cases a polynomial equation of second order was sufficient. This equation was solved and the more realistic looking value was taken.

As an example:

The results of the polynomial equation of Prospect 1 in Fig. 7-7 are 698.51 MMBOE and 3.11 MMBOE. As the latter value is more realistic according to the chart, this value was taken for the comparison.

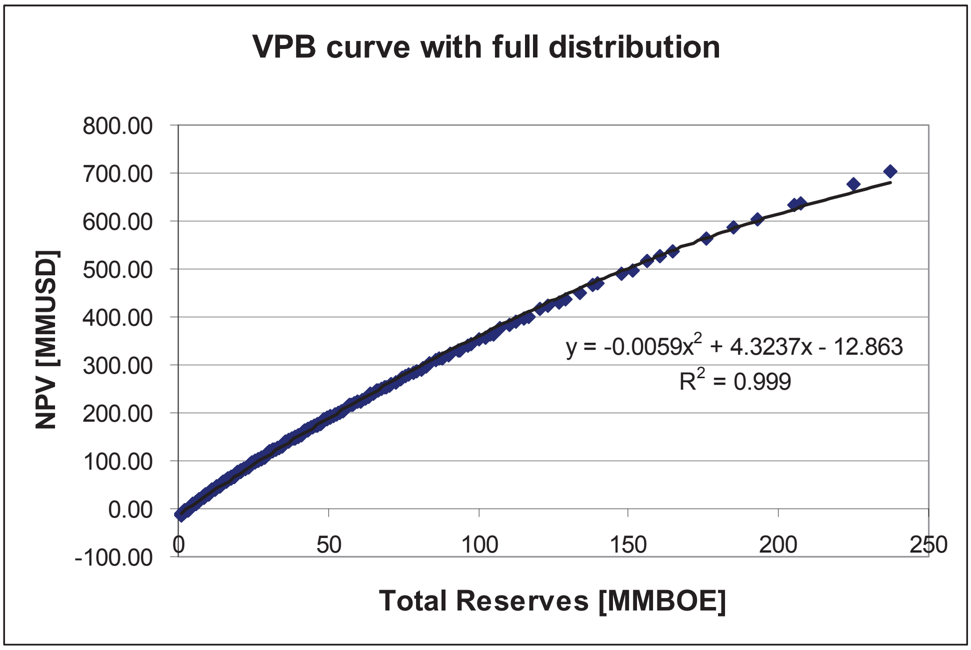

Fig. 7-7: VPB curve of Prospect 1 with a polynomial trend line added

This procedure was repeated for each of the ten prospects and the values were collected into Tab. 7-4:

	MCFS [MMBOE]	
	P-Values	Full Distribution
Prospect 1	3.34	2.99
Prospect 2	4.04	4.28
Prospect 3	4.10	4.31
Prospect 4	3.57	3.56
Prospect 5	14.25	15.09
Prospect 6	1.77	0.94
Prospect 7	2.28	2.61
Prospect 8	2.66	2.56
Prospect 9	2.65	2.69
Prospect 10	2.12	0.55

Tab. 7-4: MCFS calculated with two methods

It can be seen that the values are similar with both methods, but Prospects 6 and 10 have a relatively high deviation (Fig. 7-8). This results from positive NPV's of the P90 reserves. Only by extrapolating the trend line an approximation of the MCFS was possible with the P-value method.

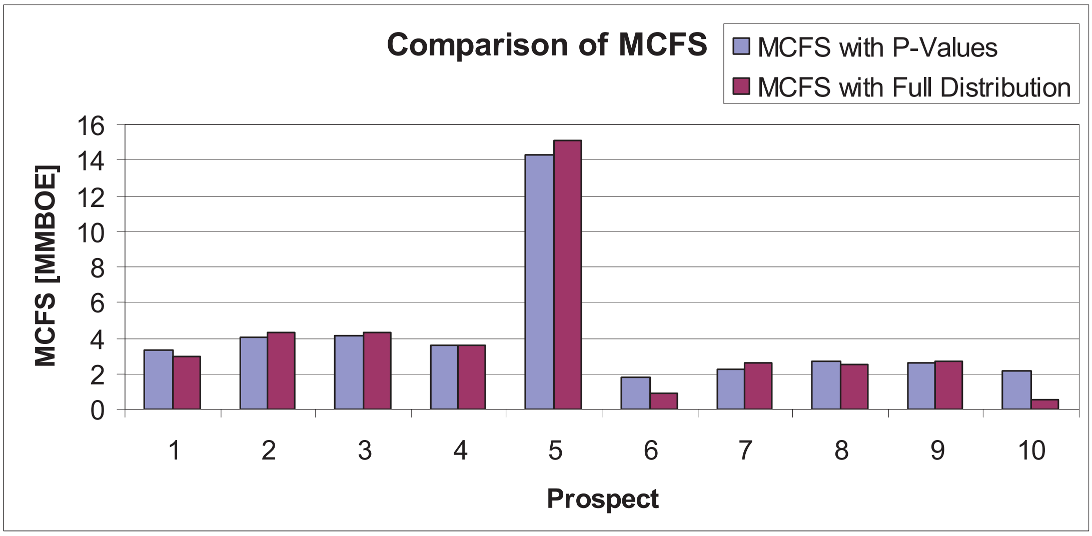

Fig. 7-8: Comparison of two ways to determine the MCFS

The total deviation of the two approaches is 3.3%, without Prospect 6 and 10. Nevertheless it is recommended to use as much data points as possible for the determination of the MCFS, best is a fully probabilistic distribution with a considerable amount of trials, otherwise an exact determination of the MCFS is not guaranteed, especially when no negative NPV is available.

7.4 New Ranking Factor for Portfolios

In the course of the evaluation an approach was developed which can be used as an additional ranking for the portfolio. The mean reserves are divided by the MCFS and the resulting factor shows the “distance” of the MCFS from the mean reserves (Tab. 7-5). When the factor is equal to one, both values are equal. Below one the MCFS is larger than the mean reserves and therefore the prospect is probably economically unattractive.

	MCFS [MMBOE]	MEAN RESERVES [MMBOE]	MEAN RESERVES/MCFS []
Prospect 1	2.99	18	6.0
Prospect 2	4.28	2.36	0.6
Prospect 3	4.31	13.76	3.2
Prospect 4	3.56	9.6	2.7
Prospect 5	15.09	3.6	0.2
Prospect 6	0.94	42	44.7
Prospect 7	2.61	18	6.9
Prospect 8	2.56	12	4.7
Prospect 9	2.69	7	2.6
Prospect 10	0.55	42.83	77.9

Tab. 7-5: Mean reserves divided by MCFS

The factor can be seen as a sign of comfort, the larger the value, the better the comfort (Fig. 7-9). Equal to the NPV calculation Prospects 6 and 10 have excellent values, Prospect 2 and 5 prove to be highly uneconomic again. In general the rank order of the prospects is the same as with the NPV (Cf. Fig 7-1).

It has to be noted that the factor will change according to the economic variables as the MCFS is based on specific economic assumptions.

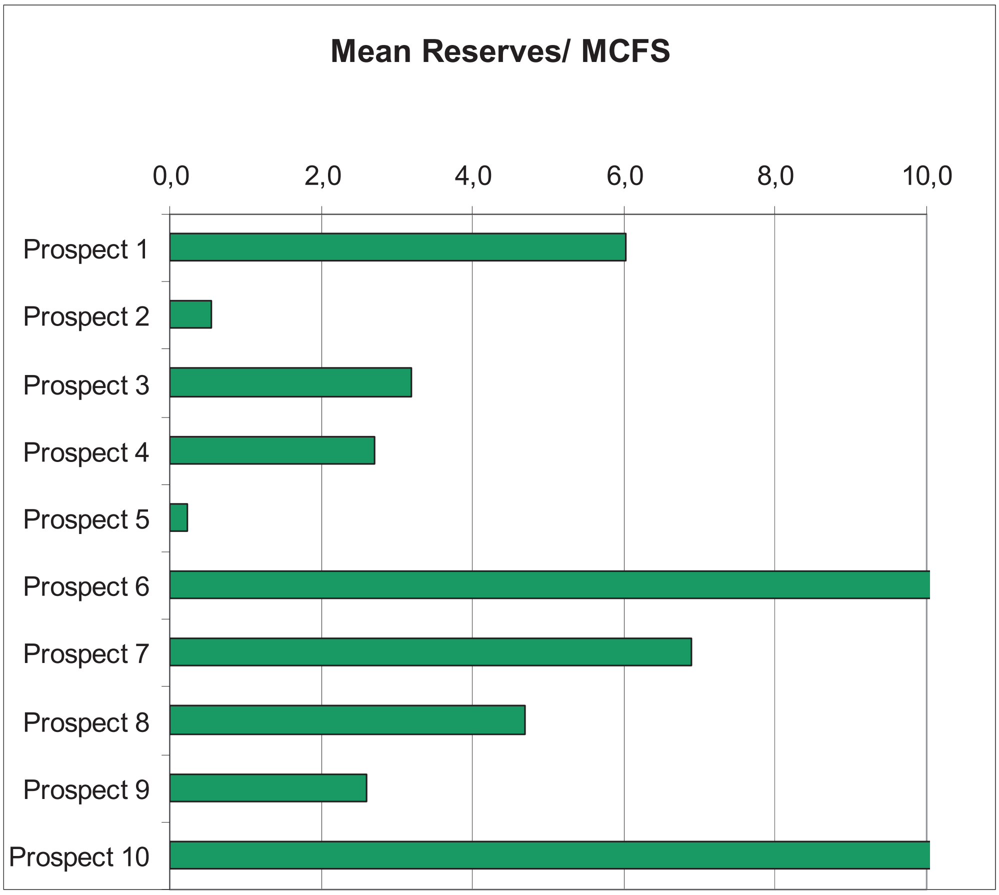

Fig. 7-9: Additional raking factor for portfolios

7.5 Developed Quick Look Methods

Beside the analysis of different economic evaluation methods and scenarios a target of this work was the development of possible economic quick look methods for prospects. In the course of the evaluation two possible approaches were investigated.

- VPB charts for plays
- MCFS vs. oil price charts for prospects and plays

7.5.1 VPB Charts for Plays

This approach is based on the assumption that the VPB curves of different prospects of a play overlap into a major VPB curve (Fig. 7-10).

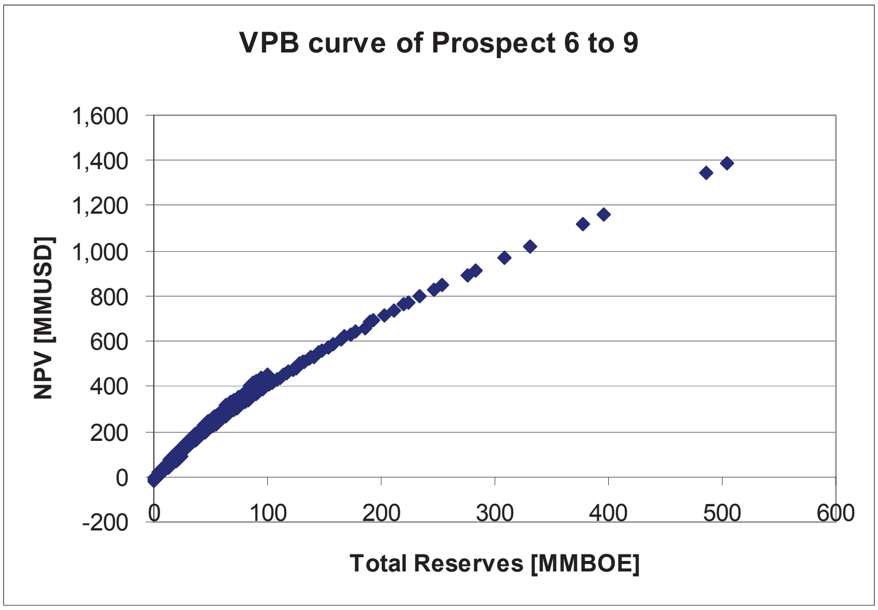

Fig. 7-10: Overlapping VBP curves of Prospects 6 to 9

This assumption was tried out on Prospects 6 to 9. The evaluation results of the Monte Carlo simulation were collected into one table and a chart was created out of the data. The result shows according VBP of all four prospects. Unfortunately, the smaller prospects were overtopped by Prospect 6, which is considerably larger. For a better comparison between the prospects of the play Prospect 1 was added to the chart and Prospect 6 removed. To increase the difference Prospect 1 was simulated with higher OPEX of 12 USD/BOE.

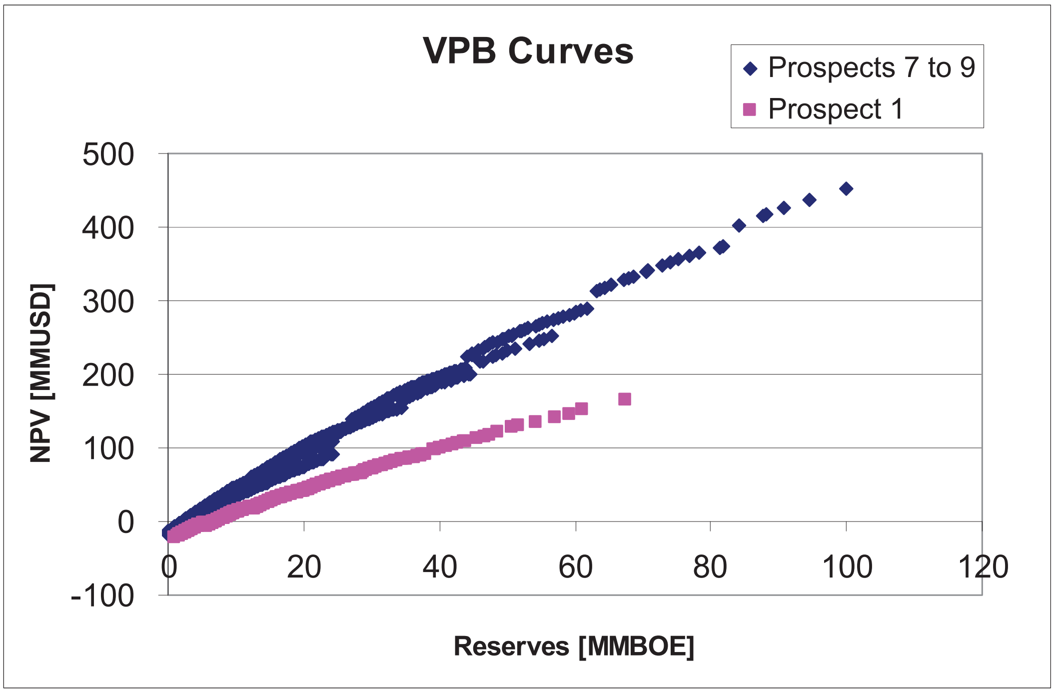

Fig. 7-11: Comparison of Prospect 1 to Prospect 7 to 9

Fig. 7-11 shows that prospects with similar conditions fit into an overlapping VPB curve albeit a little coarseness in some areas.

A VPB chart of an entire play could be a powerful instrument in prospect analysis. When a new prospect of the play is added to the portfolio a first indicative value can be determined instantly. For example, when a value of recoverable reserves is available, like 60 MMBOE, the graph can be entered and a NPV of about 300 MMUSD expected.

In addition the MCFS of the play is known, as it can be calculated in the same way as for prospects. According to Tab. 7-5 the MCFS of Prospect 7 to 9 lies between 2.56 and 2.69 MMBOE, the MCFS of the play is with 2.55 MMBOE close by.

A disadvantage of this approach is the sensitivity to changing economic input parameters. Nevertheless, it should be possible to incorporate such a VPB chart into a software program which automatically recalculates the corresponding values.

7.5.2 MCFS vs. Oil Price Charts for Prospects and Plays

Generally the MCFS decreases with increasing oil price, this can be made visible by entering the MCFS of different oil price scenarios into a chart (Fig. 7-12).

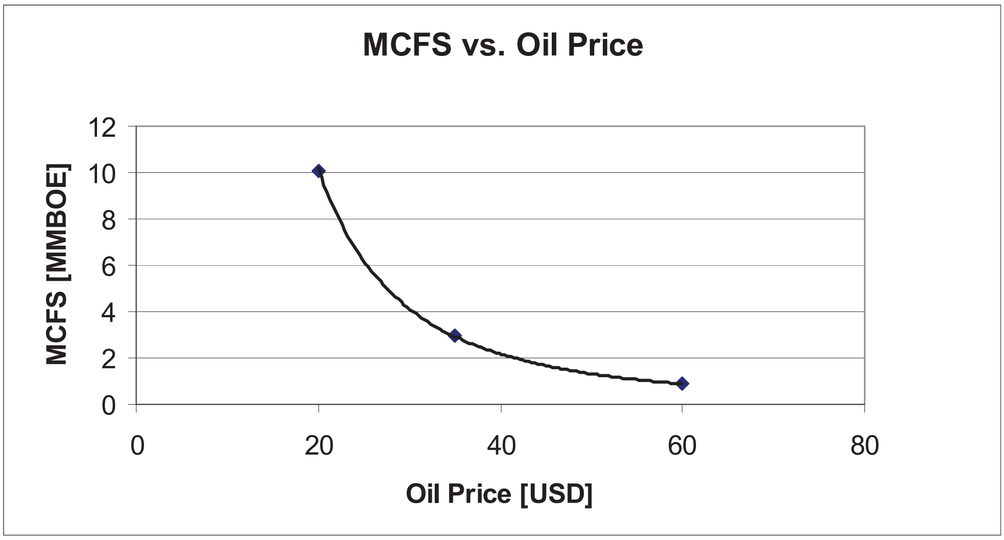

Fig. 7-12: MCFS vs. oil price chart of Prospect 1

So the MCFS of the Prospect can be determined quickly when the oil price has changed. This procedure can also be used for a play, where similar to the prospect approach, the MCFS of different oil price scenarios are entered for multiple prospects of a play (Fig. 7-13).

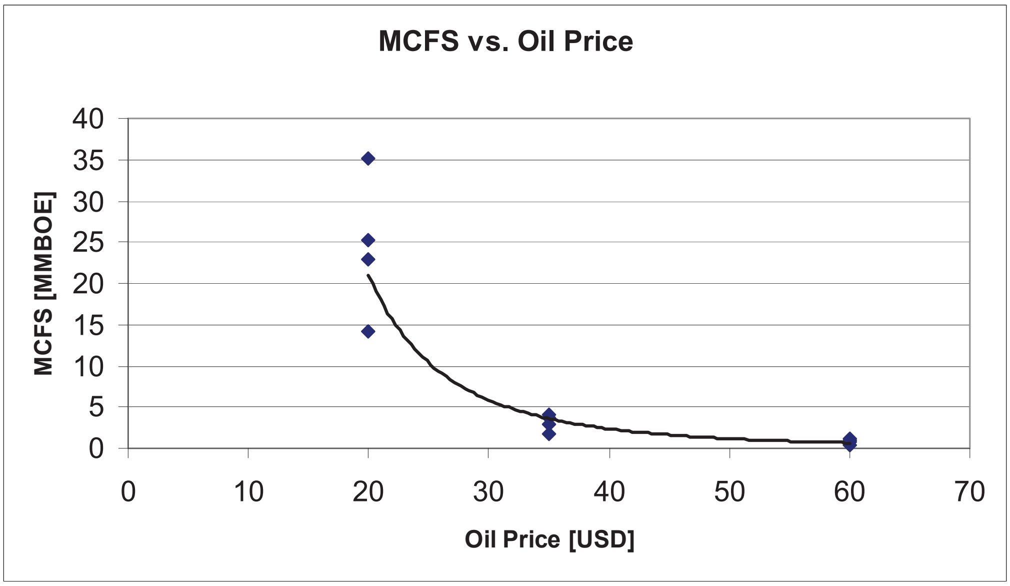

Fig. 7-13: MCFS vs. Oil Price chart of Prospect 6 to 9

An interesting side effect of this chart is the observation of the decreasing influence of the economic variables on the MCFS at increasing oil price. The scattering of the points at 20

USD is reduced to a single point at 60 USD, where all of the 4 prospects have a similar MCFS.

With this approach the disadvantage of other methods to redo the evaluation each time the oil price changes is obsolete. What it does not account for is the eventual change of economic variables due to the changing oil price like increasing rig costs due to higher energy cost.

7.6 Minimum Commercial Oil Price

In addition to the MCFS the Minimum Commercial Oil Price (MCOP) was investigated. In this case instead of the oil price the reservoir volume is kept constant. For the evaluation the fully probabilistic distribution of the oil price was used and the result plotted in a NPV versus oil price chart, accordingly named value per dollar (VPD) chart (Fig. 7-14).

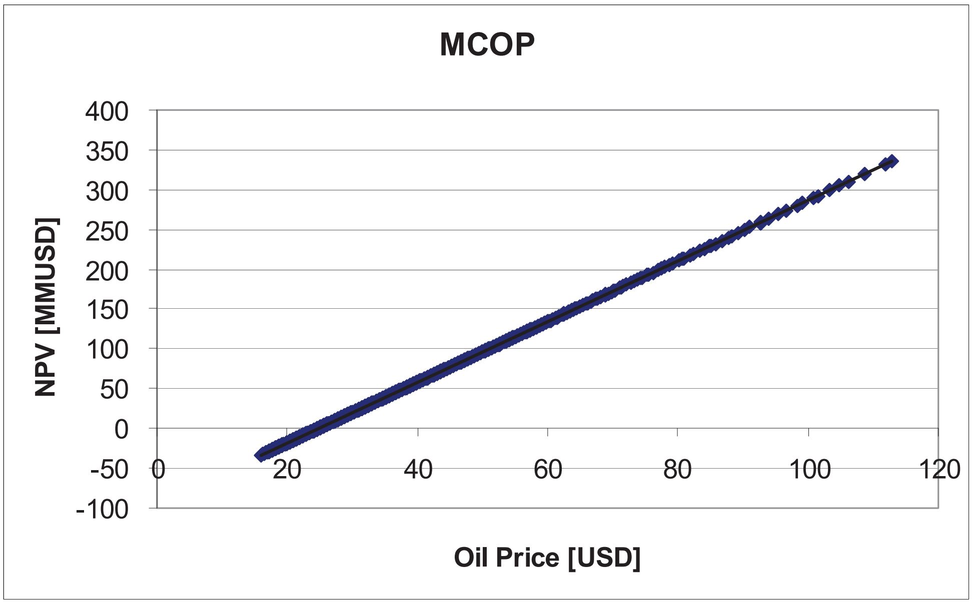

Fig. 7-14: VPD chart of Prospect 1

With this VPD chart a MCOP of 24.7 USD can be calculated. Above that oil price Prospect 1 has with the mean reserves of 18 MMBOE a positive NPV.

This procedure can be repeated for the values of P10, P50 and P90 and so gives a good impression which reservoir size is needed to be economically successful at the current oil price (Fig. 7-15).

Fig. 7-15: MCOP for P90, P50 and P10 of Prospect 1

The MCOP can be added to an inventory of currently unattractive prospects. With a changing oil price prospects of the list could be selected for further evaluation according to the new attractiveness.

7.7 Petro Canada Method of Curve Fitting

The primary interest in this method was to investigate the accuracy for determination of the MCFS. Therefore three available reserve data, the P90, P50 and P10 values, were used to calculate a NPV with the spreadsheet used for the evaluation before.

The next step was to enter these data into the curve fitting spreadsheet to determine the NPV per BOE. By entering the upper truncation of the reserve distribution, the highest reserve estimate was determined. The lowest equals the P90 value divided by four.

Further, several reserve estimates around the elbow and the expected MCFS were added for a better fitting of the curves with the regression parameters. In most cases the functions a+b/x and a+b/x^2 fitted best, for Prospect 6 the function a+b*ln(x) was chosen.

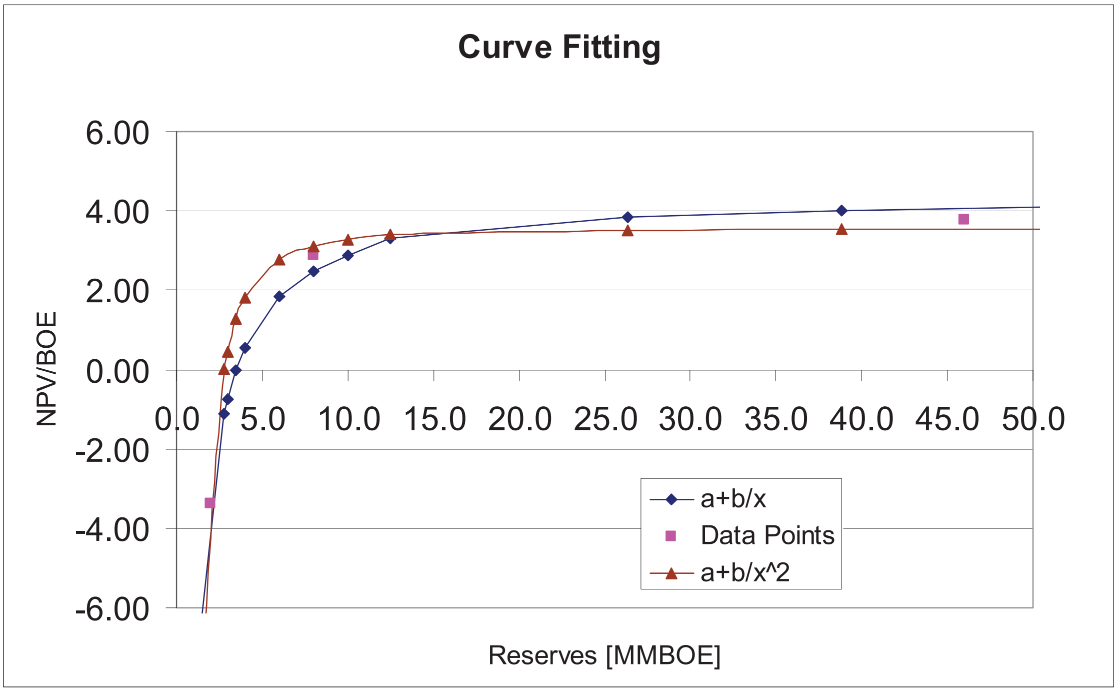

Fig. 7-16: Curve fitting of Prospect 1

The resulting data was compared with Tab. 7.4, where the MCFS was determined by a curve fitting of polynomial trend lines.

	MCFS [MMBOE]		
	P-Values	Full Distribution	Petro Canada Method
Prospect 1	3.34	2.99	2.8
Prospect 2	4.04	4.28	4
Prospect 3	4.1	4.31	4.1
Prospect 4	3.57	3.56	3.6
Prospect 5	14.25	15.09	16.7
Prospect 6	1.77	0.94	0.5
Prospect 7	2.28	2.61	2.4
Prospect 8	2.66	2.56	2.9
Prospect 9	2.65	2.69	2.8
Prospect 10	2.12	0.55	1.3

Tab. 7-6: Comparison of three methods to determine a MCFS

Tab. 7-6 shows, that there is only a small deviation between all three methods. The differences to the Petro Canada method are probably caused by the different function used for determination of the MCFS.

A disadvantage of this method is the rough estimation of the highest and lowest reserve value. A specific procedure like in the PRM may help to improve consistency of the estimates.

8 Conclusion

The use of economic evaluation methods has become an essential part in petroleum business. Investment criteria like NPV are used to identify opportunities which are expected to enhance the company's financial position. As the exploration budget is generally limited a ranking has to be applied to the prospect portfolio. To allocate the budget between the prospects consistent evaluation models are necessary to optimize the portfolio.

As there is a steady need for improvement of the evaluation methods this thesis was initiated to investigate possibilities of quick look evaluation models for prospects.
With the development of a simple spreadsheet model it was possible to show that a mean value calculation can be sufficient for determination of a first indicative value of a prospect. Anyhow, the advantages of the more sophisticated methods, like Monte Carlo simulation, should not be disregarded as they give a more thorough insight into the project.

The developed ranking factor can be easily incorporated into the evaluation procedures and may help to gain additional information of the analyzed prospect. The quick look methods can be seen as approaches and have to be tested on larger samples. The incorporation of such methods can help to improve prospect evaluation process.

Finally, in the author's opinion, longtime experience in economic evaluation is still one of the most important skills. Shortcomings of evaluation results can be more easily discovered and the knowledge of the exploration regions can be incorporated. Even though, personal bias should not influence the investment decisions as this would lead to suboptimal economic performance.

Recommendations and Outlook

The MCFS versus oil price charts have shown a decreasing influence of economic variables on the MCFS at increasing oil price. A sensitivity analysis of the economic drivers could discover the influencing factors of the MCFS. This would be beneficial for updating the charts when new economic data is available.

To test the quick look methods on their accuracy, a project could be launched for trainees to develop diagrams for several plays in different countries. During the prospect evaluation process these charts could be tested on usefulness in daily business.

As this work primarily deals with an economic ranking of the prospects in a portfolio, the investigation of the influence of a risk based ranking should be considered.
With the use of Monte Carlo simulation the “Value at Risk” of prospects could be determined which would lead to a better understanding of the true downsides of a prospect. To analyze, if the suggested methods are feasible at such an early stage of exploration, a further thesis could be launched.

9 List of Figures

10 List of Tables

11 Bibliography

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12 Appendix

Screenshot of the production forecasting calculations of Prospect 1:

Years	Theoretical Production [MBOE/year]	Number of Wells	New wells	Actual Production [MBOE/year]
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	2283.1	5.0	5.0	1898.0
6	1993.5	5.0	0.0	1898.0
7	1740.7	5.0	0.0	1740.7
8	1519.9	5.0	0.0	1519.9
9	1327.1	5.0	0.0	1327.1
10	1158.8	5.0	0.0	1158.8
11	1011.8	5.0	0.0	1011.8
12	883.5	5.0	0.0	883.5
13	771.4	5.0	0.0	771.4
14	673.6	5.0	0.0	673.6
15	588.1	5.0	0.0	588.1
16	513.5	5.0	0.0	513.5
17	448.4	5.0	0.0	448.4
18	391.5	5.0	0.0	391.5
19	341.9	5.0	0.0	341.9
20	298.5	5.0	0.0	298.5
21	260.6	5.0	0.0	260.6
22	227.6	5.0	0.0	227.6
23	198.7	5.0	0.0	198.7
24	173.5	5.0	0.0	173.5
25	151.5	5.0	0.0	151.5
26	132.3	5.0	0.0	132.3
27	115.5	5.0	0.0	115.5
28	100.9	5.0	0.0	100.9
29	88.1	5.0	0.0	88.1

Screenshot of the economic calculations of Prospect 1

Years	Actual Production [MBOE/year]	Gross Value [MMUSD]	Gross Value minus OPEX [MMUSD]	Well Cost [MMUSD}	CAPEX [MMUSD}		Cash Flows [MMUSD}
1	0	0	0	6.80	0		-6.80
2	0.00	0.00	0.00	0.00	6.72		-6.72
3	0.00	0.00	0.00	0.00	13.43		-13.43
4	0.00	0.00	0.00	0.00	13.43		-13.43
5	1898.00	66.43	56.94	34.00	0.00		14.40
6	1898.00	66.43	56.94	0.00	0.00		48.40
7	1740.67	60.92	52.22	0.00	0.00		44.39
8	1519.88	53.20	45.60	0.00	0.00		38.76
9	1327.10	46.45	39.81	0.00	0.00		33.84
10	1158.77	40.56	34.76	0.00	0.00		29.55
11	1011.79	35.41	30.35	0.00	0.00		25.80
12	883.46	30.92	26.50	0.00	0.00		22.53
13	771.40	27.00	23.14	0.00	0.00		19.67
14	673.56	23.57	20.21	0.00	0.00		17.18
15	588.12	20.58	17.64	0.00	0.00		15.00
16	513.52	17.97	15.41	0.00	0.00		13.09
17	448.39	15.69	13.45	0.00	0.00		11.43
18	391.52	13.70	11.75	0.00	0.00		9.98
19	341.86	11.96	10.26	0.00	0.00		8.72
20	298.49	10.45	8.95	0.00	0.00		7.61
21	260.63	9.12	7.82	0.00	0.00		6.65
22	227.57	7.97	6.83	0.00	0.00		5.80
23	198.71	6.95	5.96	0.00	0.00		5.07
24	173.51	6.07	5.21	0.00	0.00		4.42
25	151.50	5.30	4.54	0.00	0.00		3.86
26	132.28	4.63	3.97	0.00	0.00		3.37
27	115.50	4.04	3.47	0.00	0.00		2.95
28	100.85	3.53	3.03	0.00	0.00		2.57
29	88.06	3.08	2.64	0.00	0.00		2.25