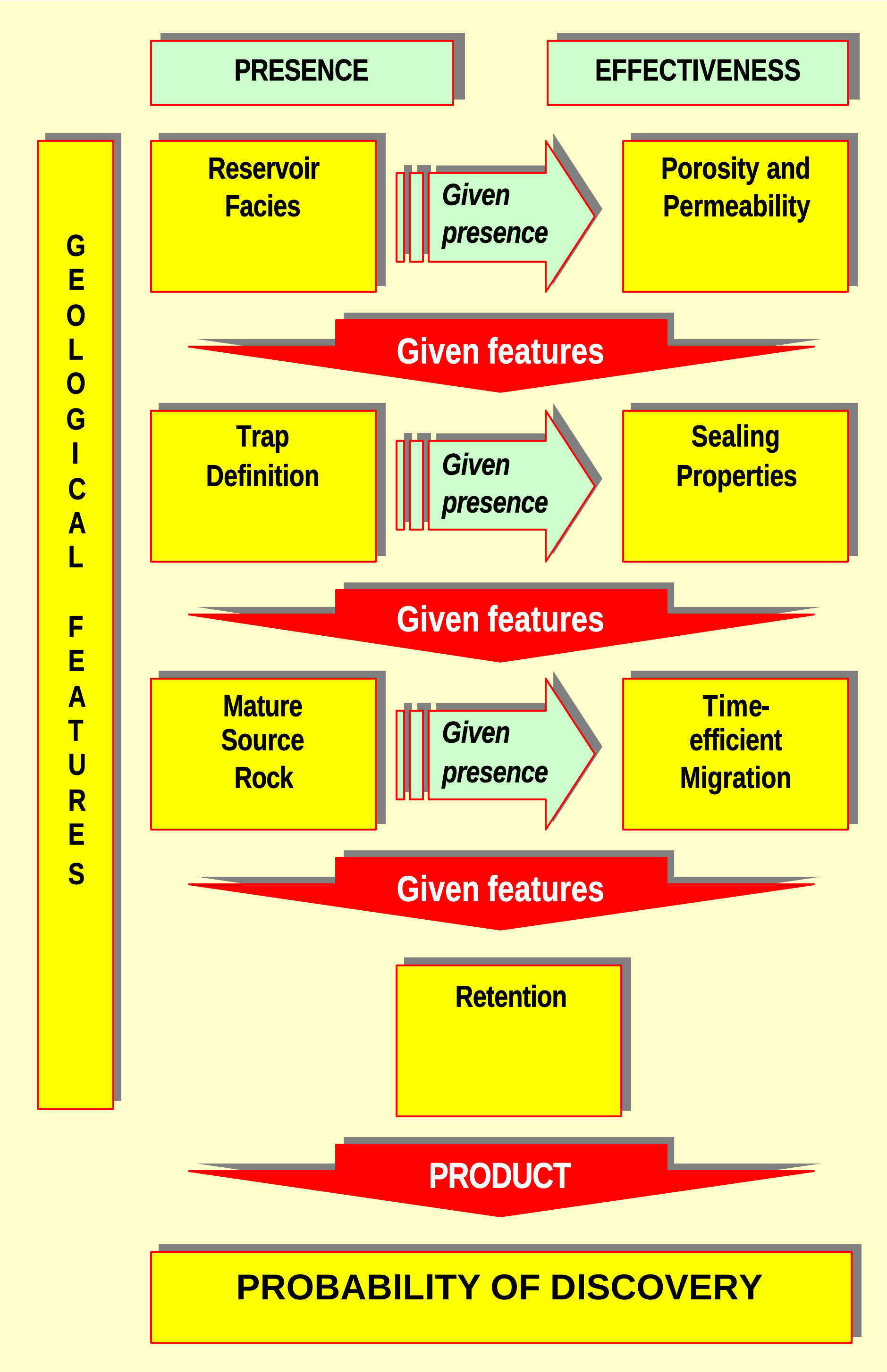
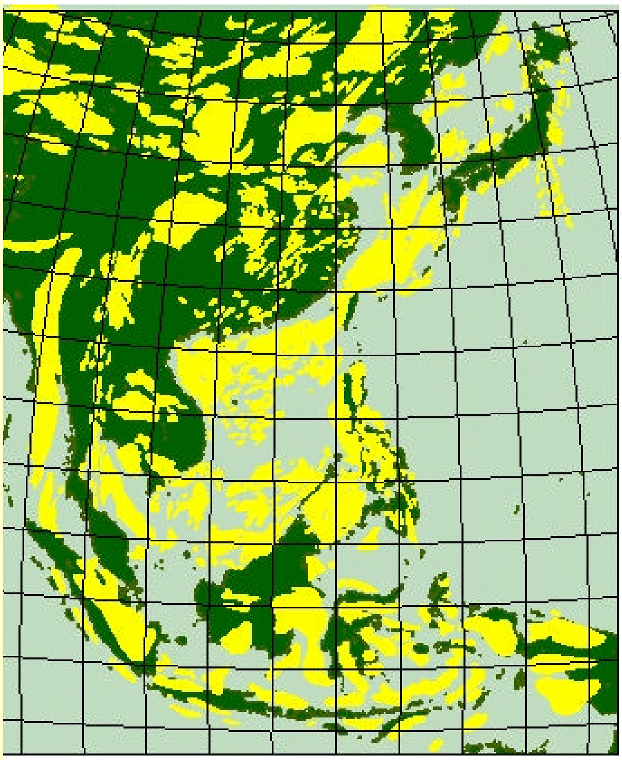
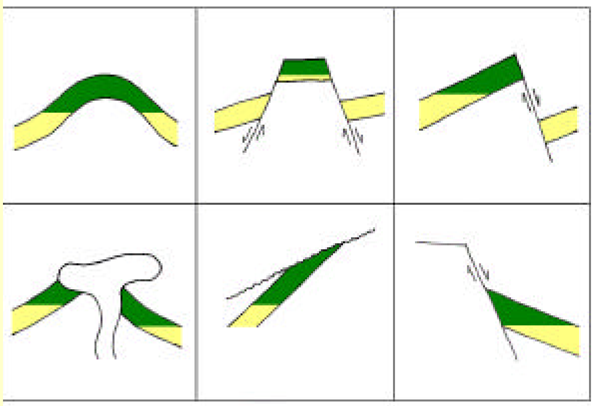
The CCOP
Guidelines for Risk Assessment of Petroleum Prospects







July 2000

CCOP

The Coordinating Committee for Coastal and Offshore Geoscience Programmes in East and Southeast Asia (CCOP) is an intergovernmental organisation with purpose to carry out joint applied geoscience programmes for sustainable development of the coastal and offshore areas in East and Southeast Asia.

The CCOP ("Coordinating Committee for Offshore Prospecting in Asia") was initiated in 1966 by China, Japan, Republic of Korea and The Philippines under the auspices of ESCAP and the United Nations. CCOP became an independent intergovernmental organisation in 1987 based on the common understanding of its member countries and the aspirations of the United Nations. The name was changed in 1994, but the acronym CCOP was retained. CCOP has during this period devoted itself to co-ordination of, and co-operation in, scientific activities related to coastal and offshore areas with respect to geological/geophysical surveys, regional map compilations, database development, development of human resources and transfer of state of the art technology.

CCOP has divided its technical activities into four sectors:

- the energy sector,
- the mineral sector,
- the coastal zone sector and
- the geo-hazard sector.

CCOP has 11 member countries; Cambodia, China, Indonesia, Japan, Malaysia, Papua New Guinea, The Philippines, Republic of Korea, Singapore, Thailand and Vietnam.

CCOP has been supported by 14 co-operating countries and several international organisations. For the last few years, the major contributing donor-countries have been Japan, the Netherlands and Norway.

The CCOP Technical Secretariat is responsible for the daily co-ordination of all activities carried out by CCOP. The Secretariat is headed by a Director, who is reporting to the CCOP Steering Committee consisting of one permanent representative from each member country. The CCOP Technical Secretariat is located in Bangkok, Thailand.

CCOP's present activities are aimed at:

- development of human resources in the public sector,
- transfer of tailor-made technology to its member countries,
- promotion of technical co-operation among member countries,
- compilation of regional geological data,
- co-ordination of joint activities within the four sectors of CCOP.

Preface

Petroleum resources are a key factor for sustainable development of the economy of the CCOP member countries. Therefore, in 1993-94, CCOP initiated the preparation of a common project proposal for the assessment and economic evaluation of petroleum resources. The Resource Evaluation and Planning Project (REP) was formally approved for funding by the Norwegian Agency for Development Cooperation (NORAD) in August 1995 (Phase 1) and in July 1996 (Phase 2). The project comprised training courses, workshops and the purchase of assessment software, together with bilateral seminars.

As part of the REP phase 2 project, in which nine of the CCOP member countries have participated, two working groups were established. One of these groups was given the task of compiling the Guidelines for Risk Assessment of Petroleum Prospects.

The CCOP Guidelines for Risk Assessment of Petroleum Prospects have been compiled by Mr. Jan-Erik Kalheim (REP II Project Coordinator), Mr. Bundiit Chaisilboon (Department of Mineral Resources, Thailand) and Mr. Simplicio P. Caluyong (Department of Energy, the Philippines). They have been assisted by the CCOP Technical Secretariate, the Norwegian Petroleum Directorate (NPD) (Per Blystad, Inger P. Fjærtoft and Paul W. Grogan), Professor Richard Sinding-Larsen (Norwegian University of Technology and Science), and by all participants of the working group.

The compilation is also based on data and information passed on during the previous CCOP projects supported by NORAD, including the Working Group for Resource Assessment (WGRA) and the Oil and Gas Resource Management (OGRM).

This publication is dedicated to the memory of Mr. Jan-Erik Kalheim, the REP II Project Coordinator, who died suddenly during the finalisation of the project. Jan-Erik Kalheim became acquainted with CCOP during workshops under the OGRM project. In this capacity he also strongly influenced the development of the REP Project. He was the most influential advisor in most of the workshops carried out in the REP project, and the driving force in the working groups for resource classification and risk assessment. Based on his extensive experience with these subjects in the NPD, he provided invaluable input and nourished the momentum of the projects by his dedicated participation and interest. CCOP is sad to have lost a true friend and an outstanding professional geologist. For our mutual benefit, and to honour the memory of Jan-Erik Kalheim, we strongly encourage professionals in all CCOP member countries, together with other petroleum producing countries, to employ these guidelines in combination with the CCOP petroleum classification system.

Dr. Sahng-Yup Kim
Director CCOP

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1. Introduction

The purpose of risk assessment in petroleum exploration is to estimate the probability of discovery prior to drilling of a mapped prospect. Risk assessment plays a significant role in petroleum exploration, not only at the prospect level but also at the play level. The probability of discovery is a value that is used both during the calculation of the economic value of the prospect, and as an important factor in the assessment of the undiscovered resources in a given area during play evaluation.

In exploration for oil and gas prospects we are dealing with a considerable degree of uncertainty. Experience shows that on average as much as 6 out of 10 drilled geological structures are dry. Furthermore, even in well-known basins where hydrocarbons are identified, experience shows that in general only 50% of these discoveries will be developed as profitable oil and gas fields.

To estimate the probability of discovery is an important part of prospect evaluation. However, experience has also shown that geologists perform risk assessment in a very subjective manner. Large variations have been documented when various oil companies have assessed the same prospect. It is clearly desirable to employ a repeatable risk assessment procedure which is as objective as possible.

The CCOP risk assessment guidelines have been prepared to aid in providing consistency and in promoting objectivity when the risking of prospects or plays are being performed using analytical tools such as Monte-Carlo simulation or stochastic calculation methods. These guidelines provide general procedures for how to perform risk assessment. In some cases, however, adjustments to the guidelines may be necessary in the light of local geological knowledge of relevant areas and according to national requirements.

Geological risk assessment requires an evaluation of those geological factors that are critical to the discovery of recoverable quantities of hydrocarbons in a mapped prospect. The probability of discovery is defined as the product of the following major probability factors, each of which must be evaluated with respect to presence and effectiveness:

- Probability of reservoir
- Probability of trap
- Probability of hydrocarbon charge
- Probability of retention of hydrocarbons after accumulation

The probability of discovery is an important input parameter during the economic evaluation and profitability studies of mapped prospects. It is also an important tool in exploration strategy, especially when assessing the ranking of prospects; i.e. which of a portfolio of prospects is most favourable with respect to the predicted volume of oil or gas, its chance of success and economic value. The third category of application is during the assessment of the undiscovered resources in a given area.

2. The Probability Concept

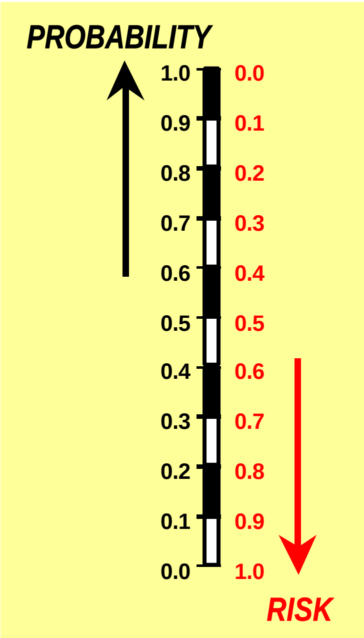


Fig. 2.1 Probability vs. risk

The probability scale ranges from 0.0 to 1.0 where the end points of the scale; P = 1.0 means 100% certainty and P = 0.0 means 0% certainty. The opposite of probability is risk, as shown on the left (Fig. 2.1).

Probability theory provides four fundamental rules, which must be considered when dealing with prospect or play risk assessments:

(1) The probability of a given occurrence or event is equal to 1 minus the risk for this event not occurring.

$P_{prob.} = 1 - P_{risk}$

This is a definitive and obvious statement, but is nevertheless an important relation when dealing with situations such as: *"either one or another event, or both events" (see rule no 4 below)*.

(2) The probability of the simultaneous occurrence of several independent events is equal to the product of their individual probabilities (the multiplication rule).

$P = P_a \times P_b \times P_c \times P_d$

This second rule is used when we estimate the probability of discovery for a mapped prospect. The prospect probability is the product of several independent factors. CCOP employs four geological factors (reservoir, trap, petroleum charge and retention) all of which must be present concurrently to make a discovery.

(3) Given the occurrence of several mutually exclusive events, the probability of occurrence of at least one event is equal to the sum of the probabilities of each individual event (the addition rule).

$P = P_a + P_b$

This third rule is used when dealing with several alternative outcomes such as the question of whether oil or gas will be the dominant phase in the prospect being evaluated. This rule is also frequently used when dealing with “decision trees” in which the sum of all possible outcomes is equal to 1.0. Another example is illustrated by throwing a die only once. In this case we have a total of 6 possible outcomes such that the probability of throwing 3 or less (either 1, 2 or 3) is;

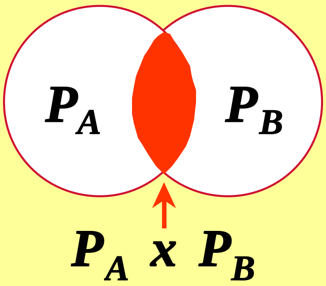
P = P1 + P2 + P3 = 1/6 + 1/6 + 1/6 = 3/6 = 0.5

(4) The probability of either one or both of two independent events can be estimated by calculating the risk that neither of the events will occur (the combination rule).

$(1-P) = (1 - P_a) \times (1 - P_b)$

This fourth rule is used when risking outcomes that are dependent on one or more events occurring. For example, during the risking of an unknown area where two potential stratigraphic levels are predicted as possible hydrocarbon sources, but only one effective source rock is required to source the prospect being risked. This rule is also used when dealing with the interdependency between prospects. The nature of the estimation of prob-

Let us assume that we are evaluating an unknown area where two potential source rocks at different stratigraphic levels (A and B) are predicted as possible hydrocarbon sources for a mapped prospect. Let us also assume that the probability of effective source rock A (P_A)=0.6 and that the corresponding probability for source rock B (P_B)=0.3. What is the probability of an effective source rock in this area? We must estimate the probability of either A or B, or both. This can be estimated by combining probability rules (1) and (2). The probability of not having an efficient source rock at all (1-P) is equal to the product of the risk (1 - P_A) of source rock A and the risk (1 - P_B) of B. This can be expressed as follows:



$$\begin{aligned} (1 - P) &= (1 - P_A) \times (1 - P_B) \\ P &= 1 - (1 - P_A) \times (1 - P_B) \\ P &= 1 - (1 - 0{,}6) \times (1 - 0{,}3) \\ P &= 0{,}72 \end{aligned}$$

This example can also be solved by applying quantitative considerations as indicated by the circles on the left:

$$P = P_A + P_B - (P_A \times P_B) = 0{,}6 + 0{,}3 - (0{,}18) = 0{,}72$$

Fig. 2.2 Example of the combination rule.

ability of occurrence of a given event will always depend on available information and knowledge. Depending on the quantity of relevant information, we may classify the probabilities according to how we arrived at them:

Stochastic probability is represented by the ratio between how many times an event occurs and the total number of trials. An example is the success rate of drilling in a region. It is important to note that stochastic probability requires a statistical basis and cannot be applied directly when the database is limited. **Objective probability** is related to the extent to which available evidence/arguments support a given hypothesis. Empirical data, historical data and data from relevant analogues are used in this process. **Subjective probability** represents the sum of individual understanding of the probability of occurrence of a given event ("belief"). Such belief-based estimates should be avoided, or at least employed as little as possible. Our task as exploration geologists is to identify and evaluate evidence that contributes to the estimation of an objective probability.

3. Individual Prospect Probabilities

3.1 General introduction

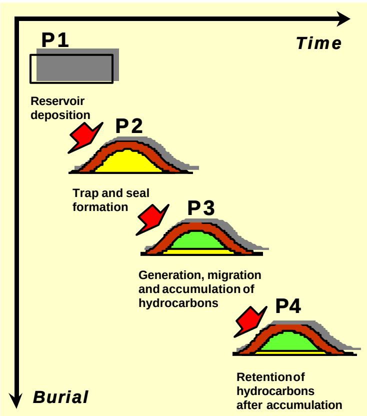


Fig. 3.1 Geochronological risk assessment

The probability of discovery is a value that is based partly on objective knowledge and historical data, partly on extrapolations and partly on our subjective judgements of local geological parameters. It is also a value that cannot directly be measured after the fact, since the result of drilling will always be either a discovery or a dry prospect.

Post-drill evaluation can be performed on a suite of exploration wells and the results analysed statistically for calibration purposes. Such studies can be very helpful in calibrating knowledge of the geological history and prospectivity in a given region. The calibration of risk parameters in an area should always be performed when new information is acquired. This will enable the consistent revision of petroleum geological models, which will in turn impact on the estimated probability of discovery of the remaining prospects.

The probability of discovery will vary from prospect to prospect, and is defined as the product of the component probabilities of well-defined geological factors, given that each of these factors is independent of the others. The four major factors are; reservoir (P1), trap (P2), petroleum charge system (P3), and retention after accumulation (P4). The probabilities of these factors are estimated with respect to the presence and effectiveness of the geological processes associated with them.

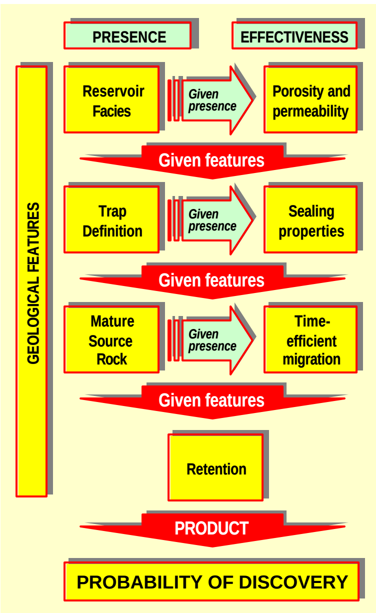


Fig. 3.2 Schematic overview of the risking procedure

The estimation of discovery probability is based on the principle of "geochronological risk assessment" (Fig. 3.1). This principle is applied in order to avoid "double risking" of the geological factors.

Geochronological risk assessment is achieved by evaluating the relevant geological processes and events in a logical time sequence. The geological process starts with the deposition of the reservoir rock, and continues with the formation of a sealed trap. We must consider source rock maturation, the migration of hydrocarbons from the mature source rock into the trap, the accumulation of hydrocarbons in the trap, and finally the post-accumulation history of the trap and its hydrocarbons.

As will be discussed in later chapters, groups of prospects may have common geological factors such as reservoir facies, mature source rock, seal mechanism, etc. (Fig. 3.2). These common factors are important when we are assessing closely associated groups of prospects. In chapter 4, the interdependency between prospects is discussed in more detail. If, for a given basin, we group together all prospects (mapped and unmapped) with common geological factors, we have defined a play. We may also define a petroleum system, which contains one or more plays, and we may also describe the interdependency between plays within the petroleum system. The most likely common geological factor within a given petroleum system is a source rock that may charge several plays (see chapter 6).

3.2 Prospect definition

In prospect evaluation a prospect is identified and mapped on the basis of geophysical and geological data. The prospect's resource potential in the success case is calculated using suitable software employing Monte-Carlo simulation, stochastic methods, or some other form of calculation. Quantitative data for the prospect is derived from the most likely geological model and is given with a range of uncertainty (Fig. 3.3). Risk is assigned to the probability of discovery of a minimum volume derived from the volumetric estimate, and is evaluated with respect to the geological risk. The reliability of the prospect definition will depend on the adequacy of the database and on the choice of reliable models for the relevant geological factors. Risk assessment is therefore an analysis of the reliability of the database and of the probability of occurrence of the geological models relevant to the prospect under evaluation. For each prospect a value of probability of discovery is estimated. The risk assessment procedure can be summarised as shown in the text column on the left.

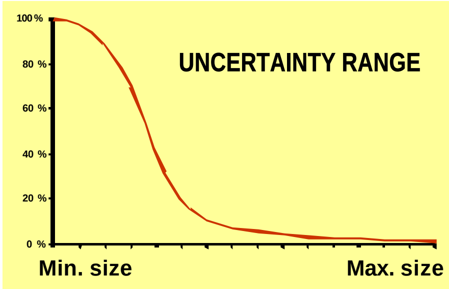


Fig. 3.3 Cumulative frequency diagram showing range of uncertainty

The relation between input parameters to the volumetric calculations and the geological risk factors is illustrated in figure 3.4.

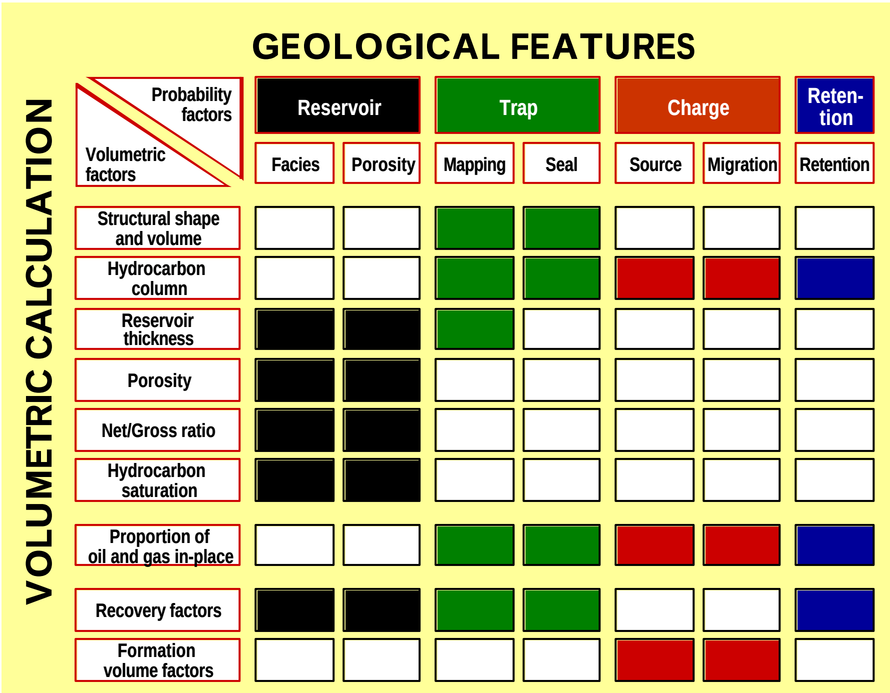


Fig. 3.4 The relation between geological models and input parameters to the volumetric calculation is shown as coloured boxes.

A major concern in the assignment of risk is to provide a probability factor that also describes the reliability of the geological models used for the determination of the input values to the volumetric calculation. The model for each geological factor must be evaluated with respect to the following:

Work plan Assessment

?? Collect all relevant geophysical and geological data.

?? Prospect identification and mapping.

?? Establish a geological model for the prospect.

?? Estimates of the prospect's resource potential, given success (Monte-Carlo simulation, stochastic calculation, etc.). Input data is based on most likely geological model for the prospect.

?? The minimum volume is evaluated with respect to geological risk on the basis of internal guidelines for the determination of probability factors. Each prospect is given a value of probability of discovery. CCOP has defined the following geological probability factors:

?? ***Reservoir***
 ?? *Reservoir facies*
 ?? *Reservoir parameters*

?? ***Trap***
 ?? *Mapping*
 ?? *Seal*

?? ***Petroleum charge***

?? **Mature source rock**

 ?? *Migration*

?? ***Retention***

?? Calibration of the probability of discovery on the basis of success ratios, previous exploration history, etc. Presentation and discussions with an internal expert panel is desirable

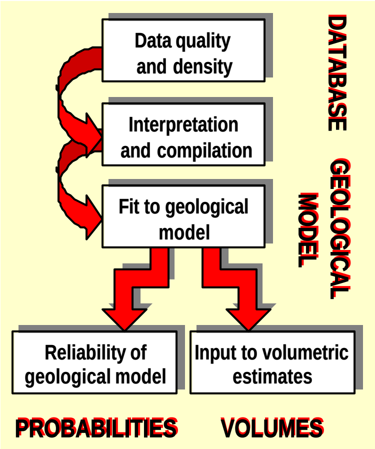


Fig. 3.5 Schematic illustration of the relation between risk assessment and volume estimation.

a) The database must be assessed with respect to data quality, data density and its relevance to the prospect under evaluation. The database consists of geological, geochemical and geophysical data.
b) The database must be interpreted and compiled, in most cases by interpolation or extrapolation, to establish a model for the relevant geological factors (fig. 3.5).

3.2.1 The database

The database may consist of seismic data, well data, surface geological data, gravimetry and magnetometry. The database must be evaluated with respect to its coverage and distribution together with its quality and relevance to the prospect under evaluation (fig. 3.6).

Data control is crucial for the establishment of reliable geological models for prospects, and is therefore an important concern when performing risk assessment. In some cases, we will wish to make an economic assessment of additional data acquisition. The certainty surrounding the probability of discovery factor before and after new data are acquired will be an important consideration in such assessments.

	DATA RELEVANCE	DATA COVERAGE	DATA QUALITY
SEISMIC DATA	Critical for prospect identification and mapping. Also important for mapping of basin configuration.	Seismic grid density compared to prospect acreage.	Critical for prospect identification and mapping.
WELL DATA	Critical for correlation to seismic data, and determination of geological models.	Number of wells penetrating relevant stratigraphic intervals.	Critical for correlation to seismic data, and determination of geological models.
SURFACE DATA	Limited relevance for prospect identification, quite useful for determination of geological models	Sampling density critical for establishment of correct geological model.	Only useful if correlation to seismic data is possible (direct or indirect).
GRAV./MAG. DATA	Useful mostly for establishing regional geological models; identification of basement highs, estimates of total sediment thickness, basin configuration and occasionally for prospect definition.		
GENERAL	Depending on distance to prospect.	Critical for interpolation and extrapolation of geological models to given prospect.	Must be evaluated with respect to existence of alternative interpretations and models.

Fig. 3.6 Some general relationships between data relevance, coverage and quality.

3.3 Geological models and risk assessment

Volumetric estimation and risk assessments are sometimes inter-related processes. If risk assessment shows a very low chance for the predicted geological model(s), the model(s) should be re-evaluated and input parameters in the calculations changed accordingly.

In the risk assessment process it may be useful to establish a set of general qualitative descriptions for the relative probability scale. These are proposed in the table below (Fig. 3.7). The scale is related to the certainty attached to the model for the relevant geological factor and to data control.

A distinction is also drawn between proven geological models and analogue/theoretical models. These expressions may be useful during discussions related to the assignment of probability factors.

P	General scale	Analogue or theoretical models	Proven geological models	P
1.0	Condition is **virtually to absolutely certain**. Data quality and control is excellent.	Only possible model applicable for the concerned area. Unfavourable models are impossible.	Identical geological factor to those found in fields and discoveries in immediate vicinity. Conditions are verified by unambiguous well and seismic control.	1.0
0.9		The model is very likely to absolutely certain. Unfavourable models are not impossible.		0.9
0.8	Condition is **most probable**. Data control and quality is **good**. Most likely interpretation.	The model is very likely. Only minor chance that unfavourable models can be applied.	Similar geological factor successfully tested by wells in the trend. Lateral continuity is probable as indicated by convincing well and seismic control.	0.8
0.7		The model is likely to very likely. Unfavourable models can be applied.		0.7
0.6	Condition is **probable** or data control and quality is **fair**. Favourable interpretation.	The model is mor likely than all otherunfavourable models.	Similar geological factor is known to exist within the trend. Lateral continuity is probable as indicated by limited well and seismic data.	0.6
0.5		Likely model, however, unfavourable are also likely.		0.5
0.4	Condition is **possible** or data control and quality is **poor to fair**. Less favourable interpretation possible.	Unfavourable models are more likely than applied model.	Similar geological factor may exist within the trend. Valid concepts, but unconvincing data only hints at possible presence of the feature.	0.4
0.3		The model is questionable. and unfavourable models are likely to very likely.		0.3
0.2	Condition is **virtually to absolutely impossible**. Data control and quality is **excellent**.	The model is unlikely and very questionable. Unfavourable models are very likely.	The geological factor is not known to exist within the trend. Conditions are verified by unambiguous well and seismic control.	0.2
0.0		The model is unlikely and highly questionable. Unfavourable models are very likely to certain. .		0.0

Fig. 3.7

In the following chapters describing the assignment of probability to each individual geological factor, a table is employed which allows us to take into account both the geological properties and the data quality/control related to each factor. It is important to emphasise, however, that these tables are general guidelines, which may be modified in the light of local knowledge and experience from previous exploration activities in the region concerned.

All prospect definitions are based on geological models incorporating reservoir, trap and petroleum charge, together with an evaluation of the probability of the retention (preservation) of hydrocarbons after accumulation. Risk assessment is an analysis of how reliable these geological models are for the prospect under consideration, given that the database is adequate for establishing and supporting these models. We can distinguish between models based on direct and indirect data.

Geological models based on direct data

These are models that are supported by data from nearby wells or other relevant data points. Such data points may be described as "direct" data, and as such will tend to confirm or disprove the geological model. Probability factors should be assigned based on interpolation or extrapolation from these data points. Distance to the data and subsequent modification (deterioration or improvement) of the geological model should be evaluated. A regional probability map for each factor may be useful if the database justifies it. According to Otis and Schneidermann (1997), models supported by the presence of direct data may be termed "favorable", and the probability of occurrence in such cases will have low risk values of between 0.7 and 0.9. If direct data do not support the model, the probability of occurrence is high risk and termed "unfavourable", and will be assigned values of between 0.1 and 0.3.

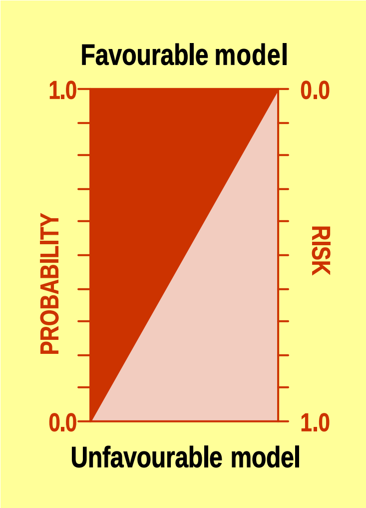


Fig. 3.8 Schematic relation between favourable and unfavourable models.

Geological models based on indirect data

Geological models based on indirect data are often referred to as theoretical models. They are necessary in areas where we have little or no "direct" data in the form of wells, and are therefore often based on analogue models taken from other basins. With indirect data, we depend on a model that we construct rather than on a model based on the interpolation and extrapolation of available data. Our opinions may be supported to some extent but not confirmed with data, and the degree of uncertainty for many of the geological factors in our model is probably large. According to Otis and Schneidermann (1997), models supported by the presence of indirect data may be described as "encouraging", and will allow us to assign relatively low risk probabilities of occurrence in the range between 0.5 and 0.7. If indirect data do not support the model, our model may be termed "questionable", and the likely range of probabilities will be between 0.3 and 0.5. If new data are acquired, it may be possible to modify the probability of occurrence towards either "favourable" or "unfavourable" (Fig. 3.8).

3.3.1 Reservoir

The probability of the presence of an effective reservoir rock with minimum properties as assigned in the volumetric estimate of the prospect, **P1**, comprises two components. The first of these is the probability of the existence of reservoir facies with minimum properties such as net/gross ratio and thickness. The second is the probability that the reservoir parameters will be effective in terms of porosity, permeability and hydrocarbon saturation.

PROBABILITY OF EFFECTIVE RESERVOIR

P1 = P1a x P1b

P1a: Probability of existence of reservoir facies with minimum net thickness and net/gross-ratio as applied in the resource assessment, and

P1b: Probability of effectiveness of the reservoir, with respect to minimum porosity, permeability and hydrocarbon saturation

These two components must be considered independently. The second component is most relevant when we are evaluating prospects at significant depths or when we are dealing with special areas of low porosity and permeability.

The following work must be performed in order to evaluate the properties and quality of the prognosed reservoir rock:

- Evaluation of all relevant wells in the area with respect to reservoir depth, diagenesis, porosity, permeability, hydrocarbon saturation, and the interrelationships between these parameters.
- Regional evaluation and facies analysis of the reservoir rock with respect to thickness, N/G ratio, threshold porosity and porosity trends with depth, and hydrocarbon saturation.
- Seismic facies analysis and sequence stratigraphy studies which have a bearing on reservoir prediction (sandstone, carbonate, etc.) and depositional environment.

The establishment of a geological model for the reservoir and its properties is based on the interpretation of geological samples (e.g. from cores), well and seismic data. An accurate prediction of reservoir properties will depend on the number of relevant data points in the area, and on the geographical distribution of these data points with respect to the prospect. In relatively mature areas, the distance to the nearest data point and indications on seismic of facies changes in the direction of the mapped prospect are important factors.

When we are dealing with relatively unknown frontier areas a more general approach must be taken. A regional depositional model for the prognosed reservoir rock must be established. According to Ulmishek (1986), the following three major categories of reservoir rocks can be identified:

1. **Massive reservoir rocks** which usually comprise thick carbonates (including reefs). Reservoir properties are determined to a great extent by cavernous porosity and fracturing, although matrix porosity may be important. Thick sandstone formations with laterally non-persistent shales may also fit this type.
2. **Stratified reservoir rocks** generally comprise one or a few sandstone beds within a relatively confined stratigraphic interval. Intergranular porosity predominates but leaching and fracturing will sometimes play a significant role. “Blanket”, often biostromal, carbonate reservoirs may also fit this type.
3. **Multistrata reservoir rocks** may comprise numerous sandstones within thick clastic formations often of paralic or deltaic origin. Intergranular porosity predominates.

RESERVOIR EVALUATION:

- Continuity/discontinuity of anticipated reservoir facies.
- Is it possible to establish alternative unfavourable models for the reservoir facies?
- Minimum reservoir thickness and net/gross ratio in the volumetric calculations
- What about the prospect location compared to the anticipated distribution of the reservoir facies?
- Data quality and data density must be evaluated. Is the geological model in the prospect location established by interpolation or extrapolation?
- How reliable is the database?

Clearly, there exist transitions between the two last categories. Categories one and three are the two that have proved to be the most effective reservoirs in a global context.

3.3.1.1 Presence of reservoir facies

When we are estimating the probability of existence of an effective reservoir we must evaluate the chance that the prognosed reservoir rock possesses at least the minimum values of N/G-ratio and thickness that we applied in the volumetric assessment. It is also important to note that it is *the net reservoir thickness* (thickness x net/gross ratio) which has consequences for our resource estimates.

Prospect evaluation is based on a geological model for reservoir facies. The model must be defined with respect to depositional environment and the lateral distribution of the prognosed facies. When performing risk assessment, the facies model must be evaluated with respect to the questions in the text box on the left.

DEPOSITIONAL ENVIRONMENT

- Vertical and lateral facies distribution
- Thickness variations

General guidelines related to reservoir facies are listed in the table in figure 3.9.
The guidelines assume an adequate and reliable database. Note that for clastic reservoirs the sand/shale ratio in the depositional system will determine whether we choose the lower or the higher end of the probability range.

These general guidelines should be adjusted to local conditions, and/or on the reliability of the database.

	Depositional environment \ Data reliability	Direct data, proximal deposits	Direct data, more distal deposits	Limited data, discontinuous deposits	Indirect data, seismic sequence analysis
Marine	Shallow marine, "blanket"	0.9 - 1.0	0.7 - 0.8	0.6 - 0.7	0.4 - 0.6
	Coastal, deltaic, tidal	0.8 - 1.0	0.7 - 0.8	0.6 - 0.7	0.4 - 0.6
	Submarine fan	0.7 - 0.8	0.5 - 0.6	0.3 - 0.5	0.1 - 0.3
	Carbonates	0.8 - 1.0	0.6 - 0.8	0.5 - 0.7	0.3 - 0.5
Continental	Lacustrine deltaic	0.7 - 0.9	0.5 - 0.7	0.4 - 0.6	0.3 - 0.5
	Alluvial fan, braided stream, meand. chan.	0.7 - 0.9	0.5 - 0.7	0.4 - 0.6	0.3 - 0.5
	Eolian	0.8 - 1.0	0.6 - 0.8	0.4 - 0.6	0.4 - 0.6
Others	Fractured basement	0.4 - 0.6	0.3 - 0.5	0.2 - 0.4	0.1 - 0.3
	Fractured, porous lava	0.4 - 0.6	0.3 - 0.5	0.2 - 0.4	0.1 - 0.3

Fig. 3.9 Probability scheme. Presence of effective reservoir facies.

PARAMETERS TO EVALUATE

- well data
- reservoir depth, diagenesis, etc.
- porosity and permeability plots and maps
- facies related porosity trends
- seismic velocities

3.3.1.2 Effective pore volume

During prospect evaluation a model for lateral and vertical (depth) distribution of reservoir properties should be established in order to define reasonable cut-off values for effective reservoir permeability and porosity. When performing risk assessment, we are evaluating the probability of porosity and permeability being greater than the minimum value. An analysis of the major factors controlling reservoir effectiveness should be performed as indicated in the text box on the left.

Also during the evaluation of reservoir facies and effectiveness, it is important to have a clear understanding of the extent to which the prognosed models are proven or analogue/theoretical.

FACTORS CONTROLLING RESERVOIR EFFECTIVENESS

- Diagenesis, illitisation, calcite cementation and other processes which may cause deterioration of reservoir quality.
- Secondary porosity.
- Fracturing and its impact on reservoir quality.
- Pressure conditions that may influence the preservation of porosity and/or permeability. High pressure in the reservoir may reduce porosity. Overpressure may maintain high porosity at great depths.
- Early migration may contribute to preservation of porosity and permeability even at great depths.

PROBABILITY OF EFFECTIVE TRAP

P2 = P2a x P2b, *where:*

P2a: Probability of presence of the mapped structure with a minimum rock volume as prognosed in the volume calculation.

P2b: Probability of effective seal mechanism for the mapped structure.

The risk analysis of porosity is closely related to the interpretation and choice of porosity data as input to the volumetric calculation. In general, available well data are used to establish regional porosity-versus-depth trends from which the scatter in data points is used to define the minimum, most likely and maximum values for the average porosity for a given depth interval (fig. 3.10).

In most cases we take account of the uncertainty in the porosity values by using the minimum average porosity value in the input parameters for the volumetric calculation. However, the probability of effective porosity may be a critical parameter when we are evaluating prospects at great depths, or if we are dealing with special areas of generally low porosity (i.e. lower than the threshold value for porosity). When we are evaluating prospects at great depths, we should estimate the minimum threshold porosity for efficient production of hydrocarbons. This value should be used as the minimum value in the volumetric calculation.

Other regional factors (i.e. reservoir facies, tectonic uplift, regional erosion, and diagenesis) may also influence porosity values.

We should also be aware that there is a substantial difference between porosity data measured on cores and data calculated from electric logs. The difference may be as high as 10 to 15%.

Res. depth, *(pressure, temp.)* / **Data reliability**		**Direct data, proximal deposits**	**Direct, but less data, more distal deposits**	**Limited data, uncertain correlation**	**Indirect data**
1 - 3 km	Homogeneous, clean reservoir	0.9 - 1.0	0.8 - 0.9	0.7 - 0.8	0.6 - 0.7
	Mixed, unclean reservoir	0.8 - 1.0	0.7 - 0.8	0.6 - 0.7	0.4 - 0.6
3 - 4 km	Homogeneous, clean reservoir	0.8 - 0.9	0.7 - 0.8	0.5 - 0.7	0.4 - 0.5
	Mixed, unclean reservoir	0.7- 0.9	0.6 - 0.7	0.5 - 0.6	0.3 - 0.5
> 4 km	Homogeneous, clean reservoir	0.7 - 0.9	0.5 - 0.7	0.4 - 0.6	0.3 - 0.5
	Mixed, unclean reservoir	0.6 - 0.9	0.3 - 0.5	0.2 - 0.4	0.1 - 0.3

Late uplift	Take **maximum burial** into consideration
Calcite cementation	Consider **regional studies**
Illitisation	**Regional studies, clay content**
Dolomitisation	Consider **regional studies**
Early migration	May **preserve** reservoir porosity
Secondary porosity	Pressure/solution studies, etc.

ADJUST DEPTH BOUNDARIES ABOVE TO FIT BASIN PROPERTIES

ADJUST MINIMUM POROSITY VALUE IN VOLUME CALCULATIONS

Fig. 3.10 Reservoir depth vs. data

3.3.2 Trap mechanism

The trap is a sealed structural closure or geometrical body. The probability of the presence of an effective trap, **P2**, is the product of the probability of the existence of the mapped structure as a valid geometrical closure, and of a sealing mechanism which acts in such a way that the trap's bounding surfaces enclose the minimum rock volume as defined in the volumetric calculation.

For this probability factor we must assess the probability of the existence of the minimum gross rock volume of the mapped structure. Furthermore, we must evaluate the probability of effective sealing of the structure. The sealing mechanism incorporates both the surrounding rocks and faults.

It is also important to note that the point in time of trap formation relative to the time of onset of migration will be considered as part of the evaluation of probability factor P3 (*probability of effective petroleum charge*). Issues related to tectonic and/or isostatic reactivation after accumulation of hydrocarbons will be assessed as part of the evaluation of probability factor P4 (*probability of effective retention after accumulation)*.

It is recommended that the following work be carried out before we assess the probability of an effective trap:

- Ideally, all surfaces enclosing the reservoir volume (both top and base) should be mapped. If the reservoir model indicates a geometrically uniform reservoir body (i.e. parallel top- and bottom surfaces), it will be sufficient to map the top surface.
- Establishing a geological model for our definition of the mapped structure and sealing mechanism (i.e. sealing rocks and faults must be identified).
- Spill-point relations must be defined and carefully mapped.
- Time-depth relations (depth conversion) of the sealing surfaces must be established (with associated uncertainties).
- Seismic profiles should be examined with respect to potential seismic anomalies such as hydrocarbon and lithology indicators.

When we are dealing with poorly known frontier areas a more general approach must be adopted. A regional model for prognosed trapping mechanisms must be established. According to Ulmishek (1986) the two following major categories of trap types can be identified on a global basis:

1. **Intensely deformed structural style,** where structural (including salt- and clay diapirs) and combined structural/stratigraphic traps are abundant.

2. **Slightly deformed structural style,** where structural traps are rare; stratigraphic (including paleogeomorphic) traps predominate.

In addition, Ulmishek (1986) defined two different seal types as follows:

1. **Perfect seals** are comprised of effectively impermeable rocks such as anhydrites, over-pressured shales, or other thick (hundreds of metres) plastic shale formations, and permafrost.

2. **Imperfect seals** comprise partly permeable rocks such as differentially compacted shales, dense carbonates, marls, etc., and are more common in areas of tectonic faulting and fracturing.

The evaluation of probability of existence of the mapped trap as a geometrical body must take the following issues into consideration.

- seismic data quality
- seismic coverage
- seismic interpretation
- identification of top/bottom surfaces of the reservoir
- reliability of the trap definition
- depth conversion

3.3.2.1 Presence of the mapped structure

In general, prospect mapping includes three major processes; interpretation of the seismic profiles, construction of time maps of the top (and bottom) surface, and conversion of the time maps to depth maps. The probability of correct delineation of the minimum rock volume by mapping of the top and base reservoir, calculation of areal closure and depth conversion, etc.), together with placement of the trap at the correct location have to be assessed. Risk analysis requires a careful evaluation of each step in this process.

Regarding seismic data quality, we must evaluate the possibility that the mapped geometrical body does not exist (or that the bounding surfaces enclose less than the minimum estimated reservoir rock volume). Uncertainty will arise if resolution of these surfaces on seismic profiles is poor. The seismic coverage must also be assessed. The density of seismic profiles (fig. 3.11) must be adequate to ensure that we can delineate a measurable rock volume and the spill-points of the prognosed trap. If this is not possible, our prospect should be redefined as a “lead”, and we should consider the possibility of acquiring new data in order to reduce this uncertainty in the mapping. It is important to assess whether the space between the profiles is so great that the acquisition of new data is necessary in order to confirm that the reservoir rock volume is greater than the minimum as defined in the volumetric calculation.

The process of seismic interpretation includes the picking of seismic reflectors, correlation across fault boundaries, tie between crossing profiles, etc. The structural and/or stratigraphic complexity of the prospect (fig. 3.11) must be evaluated with respect to its influence on the uncertainty in determining the minimum rock volume. In addition, the identification of the bounding reservoir surfaces (top and bottom) must be assessed. If we have not been able to identify the seismic reflectors representing the relevant bounding surfaces, we must evaluate the uncertainty of the seismic interpretation and its impact on the minimum rock volume.

The impact of depth conversion is a critical factor when we are assessing low-relief structures. Uncertainty in time-depth conversion algorithms which determine the structural apex (and thereby the top of the prognosed hydrocarbon column) will influence our estimate of the minimum rock volume. Both vertical and lateral velocity variations must be assessed. Note that seismic velocities derived from 2D-processing data have a tendency to be in the range 5-10% higher than geological average velocities. If possible, seismic velocities should be calibrated with velocities derived from nearby wells.

Seismic correlation and mapping	Data reliability	3D-seismic	2D-seismic: Dense grid size	2D-seismic: Open grid size	2D-seismic: Very open grid
Good corr., nearby wells	Low structural complexity	0.9 - 1.0	0.9 - 1.0	0.8 - 1.0	0.7 - 0.9
	High structural complexity	0.7 - 1.0	0.6 - 0.9	0.5 - 0.8	0.4 - 0.7
	Low relief, uncertain depth conversion	0.6 - 0.9	0.5 - 0.8	0.4 - 0.7	0.3 - 0.6
Uncertain corr, distant wells	Low structural complexity	0.9 - 1.0	0.8 - 1.0	0.7 - 0.9	0.5 - 0.8
	High structural complexity	0.7 - 0.9	0.6 - 0.9	0.4 - 0.8	0.3 - 0.7
	Low relief, uncertain depth conversion	0.5 - 0.8	0.4 - 0.7	0.3 - 0.6	0.2 - 0.5
Unreliable corr. analogue model	Low structural complexity	0.9 - 1.0	0.7 - 1.0	0.6 - 0.8	0.4 - 0.7
	High structural complexity	0.4 - 0.7	0.3 - 0.6	0.2 - 0.5	0.1 - 0.4
	Low relief, uncertain depth conversion	0.3 - 0.7	0.2 - 0.6	0.1 - 0.5	0.1 - 0.4

Interpretation of top surface not based on seismic reflector:	
Parallel reflectors	In general, middle to high end of range
Non-parallel reflectors	Low end of range

Area of closure/grid size:	
> 5 times	Dense grid size
2 - 5 times	Open grid size
< 2 times	Very open grid size

Fig. 3.11 Probability scheme. Presence of efficient structural closure.

3.3.2.2 Effective seal mechanism

The surrounding rocks in contact with the prognosed reservoir volume of any prospect will determine its sealing mechanism. The enclosing surfaces of the reservoir volume may be classified into three different groups (Milton and Bertram, 1992), *depositional surfaces*, *tectonic surfaces*, *and facies change-related surfaces.*

When we are assessing this factor we must evaluate the permeability of the surface (or surfaces) which define and enclose the reservoir volume. The sealing capacity of the trap will depend on the lithologies along the surfaces that enclose the reservoir rock. Only surfaces that are necessary to enclose the reservoir volume should be included. Top-, bottom- and lateral seals must be regarded as equally important. All traps can be classified into two major groups; those that depend on a *simple seal mechanism,* and those that depend on *a combined seal mechanism* as shown in table, (fig.3.12).

Seal mechanism	Top surface	Bottom, side	Structural style	Very good	Good	Accept-able	Poor
Simple seal	Con-form	N/A.	Anticline, buried highs, build-ups, faulted str.	0.9 - 1.0	0.8 - 1.0	0.6 - 0.8	0.4 - 0.6
Simple seal	Uncon-form	N/A.	Faulted structures	0.8 - 0.9	0.7 - 0.8	0.5 - 0.7	0.3 - 0.5
Combined seal	Con-form	Uncon-form	Onlap, low-stand wedge	0.5 - 0.7	0.4 - 0.5	0.3 - 0.4	0.1 - 0.3
Combined seal	Con-form	Faults	Downfaulted structures	0.6 - 0.8	0.5 - 0.6	0.3 - 0.5	0.1 - 0.3
Combined seal	Con-form	Facies shift	"shale out"	0.6 - 0.8	0.5 - 0.7	0.4 - 0.6	0.1 - 0.3
Combined seal	Uncon-form	Con-form	Subcrop structures	0.4 - 0.5	0.3 - 0.5	0.2 - 0.4	0.1 - 0.3

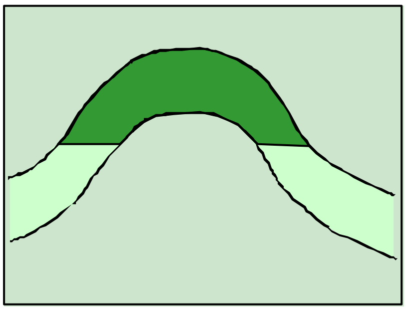
Salt, anhydrite, carbonates	**Very good** sealing properties
Thick shales	**Good** sealing properties
Thin shales	**Poor to acceptable** sealing properties
Basalt	**Acceptable to good** sealing properties
Faults cutting top surface	**Poor to acceptable** sealing properties
Juxtaposition; fault planes	Depends on sand/shale or sand/sand contact

Fig. 3.12 Probability scheme.
The probability of an effective of seal mechanism.

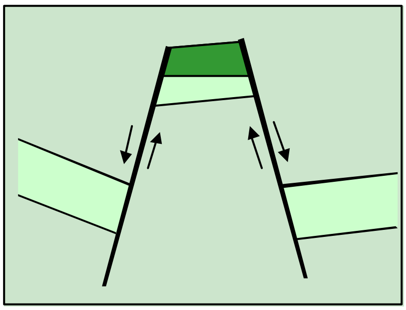
All traps defined by a sealing top surface with a 4-way closure exhibit a *simple sealing mechanism*. The distribution of the reservoir within this closure affects the pore volume, but not the sealing mechanism of the trap. Structures such as anticlines, sedimentary build-up structures (submarine fans, reefs, barrier banks, etc.), together with buried topographic highs and erosion remnants may be included in this group. Fault-dependant structures where the fault plane is part of the sealing top surface (rotated fault blocks, horst blocks, etc.) are also included in this group. The only seal risk associated with traps of this type is that related to the sealing properties of the overlying lithology (i.e. caprock). Hydrocarbon spill from these structures will generally only occur from a saddle point at the top surface.

Traps with *combined seal mechanism* include those that require either lateral and/or bottom seal mechanisms in addition to top seal, in order to define the trap. The structural map at the top reservoir surface is not sufficient to define the reservoir volume for this type of trap. Traps formed by pinch-out or the shaling out of sand-bodies, and down-faulted structures (down-thrown fault blocks) belong to this group. The seal risk associated with this group of traps is related as much to lateral and bottom surfaces as to the top surface. Spill from these structures may occur either from a saddle point in the top surface or from the deepest point where the top and lateral/bottom surfaces meet.

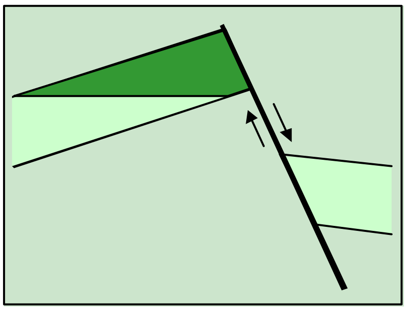
When we are assessing the risk of sand to sand contact across fault planes, we must also consider the potential "shale smearing" in the fault plane, and the dip of the sand layer that is anticipated to be in direct contact with the reservoir rock. Different trap mechanisms are shown in fig.3.13.



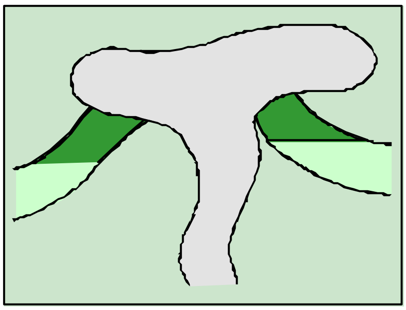
***A**. Anticline, dome*



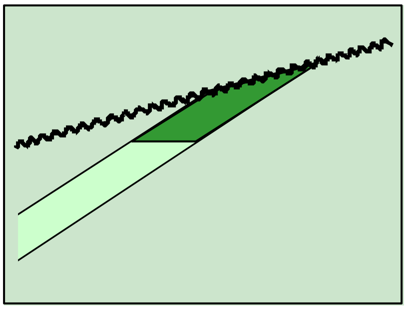
***B**. Horst*



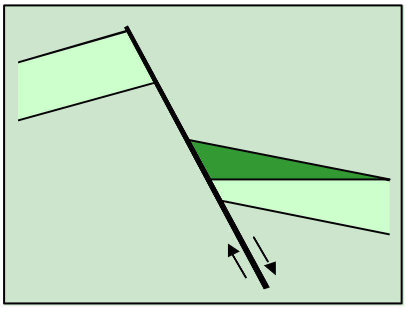
***C.** Rotated fault block (normal)*



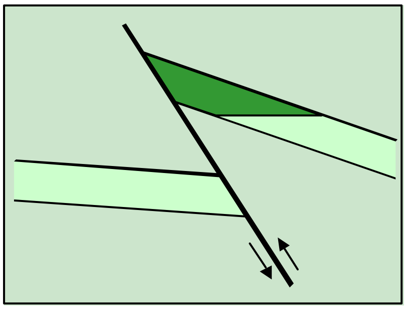
***D**. Traps formed by salt diapirism*



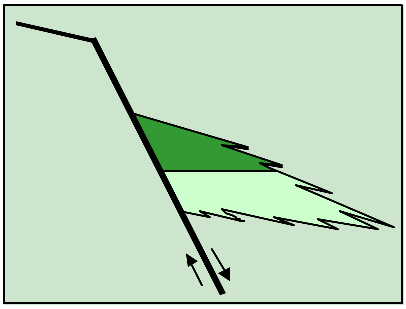
***E**. Trap formed by truncation*



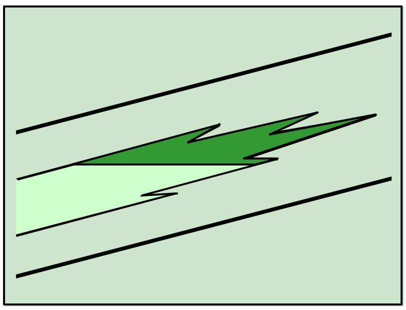
***F**. Downthrown fault block*



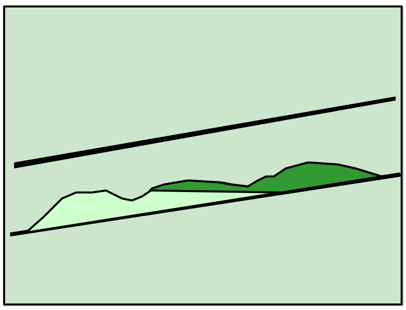
***G**. Fault block (reverse)*



***H**. Combined trap mechanism*



***I**. Stratigraphic trap ("shale-out")*



***J**. Stratigraphic trap*

Fig. 3.13 Examples of trap mechanisms.

PROBABILITY OF EFFECTIVE PETROLEUM CHARGE

***P3 = P3a x P3b*,** where:

P3a: Probability of effective source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the mapped structure.

P3b: Probability of effective migration of hydrocarbons from the source rock to the mapped structure.

FACTORS TO BE EVALUATED:

- quality and maturity of the potential source rock(s),
- what type of hydrocarbons are generated,
- volume of mature source rock within the drainage area,
- points in time for onset and end of oil migration,
- points in time for onset and end of gas migration,
- mapping of drainage area and migration routes,
- mapping of "fill-spill" relationships

3.3.3 Petroleum Charge

The petroleum charge system comprises an effective source rock (in terms of its quality, volume and maturity), and a migration mechanism for hydrocarbons from the source rock(s) to the sealed trap. The probability factor for the petroleum charge system, **P3**, is a product of the probability of effective source rock, **P3a**, and the probability of effective migration, **P3b**. Each component of the petroleum charge system, P3a and P3b, must be considered independently.

The determination of this factor requires an evaluation of source rock potential before we carry out the volumetric calculation for the prospect. We must examine the following factors.

When performing the volumetric assessment of the prospect, the potential hydrocarbon charge can be estimated by the following formula:

> *Petroleum charge = Effective drainage area x Average thickness x TOC x Transformation factor x Expulsion factor (primary migration) x Secondary migration factor*

The purpose of this calculation is to justify the trap-fill in terms of the volume of available hydrocarbons. In most areas, lack of sufficient data will introduce considerable uncertainty to these estimates. A Monte-Carlo simulation tool could therefore be very useful. The other factor relevant to the trap-fill is the sealing capacity of the structure. If the calculated charge is not sufficient to fill the prospect, the trap fill (or hydrocarbon column) must be reduced accordingly.

In unknown frontier areas a more general approach must be taken, and regional models for the predicted source rocks must be established. According to Ulmishek (1986) the following three major categories of organic matter can be identified within potential source rocks:

Humic organic matter, which is mainly terrestrial. Coal-bearing rocks are included here. Dry gas is the major hydrocarbon product.

Dispersed sapropelic organic matter is found in marine and lacustrine rocks. The content of organic matter is usually close to the Clarke level and seldom reaches 2-3% in discrete samples. Significant mixing of humic organic matter is common.

Concentrated sapropelic organic matter is found in marine and lacustrine rocks, sometimes in relatively thin formations. Average concentration of exclusive sapropelic organic matter commonly exceeds 4-5% and reaches 20% or more in individual samples.

3.3.3.1 Presence of sufficient volume mature source rock

The presence of an effective source rock is evaluated on the basis of source rock analysis, discoveries in the area and from oil/source rock correlation. The number of data points and the distance from the mapped structure to relevant data points are critical factors. A model describing the depositional environment of the source rock is necessary in order to predict its lateral extension and possible organic facies changes.

The presence of sufficient volume of mature source rock is evaluated using maturity maps that also include potential drainage areas. A simulation of the source rock maturity is necessary, and commercial basin modelling programs should be employed for such simulations.

Quality/effectiveness of the source rock

- kerogen type (I, II, III or IV)
- TOC-content
- Transformation of organic matter to oil and/or gas
- Lateral variations, distance to data points

Maturity of source rock

- "overcooked"
- gas window
- transition gas/oil window
- peak oil window
- marginal mature/onset of oil window

Volume of mature source rock within drainage area

- more than sufficient volume
- marginal volume
- inadequate volume

This probability factor is evaluated by considering the following three factors;

- the probability of adequate **quality and effectiveness** of the predicted source rock with respect to hydrocarbon generation,
- the probability of the presence of **mature** source rock within the drainage area of the prospect
- the probability of the presence of sufficient **volume** mature source rock within the drainage area

Figure 3.14 shows how quality, maturity and volume of source rock can be taken into consideration. Even though most of these parameters can be measured in the laboratory, there remains much uncertainty related to these measurements. Samples are in most cases from wells and/or geological outcrops at a given distance from the source area under consideration for our prospect. An assessment of data relevance and quality are therefore crucial factors in the risk assessment of source rock properties.

Data reliability / Depositional environment		Restricted marine or lacustrine environment with conc sapropelic organic matter	Mixed marine or lacustrine envir-onment with dispersed sapropelic organic matter	Deltaic environment with mostly humic organic matter (terrestrial; mainly gas)
Proven source rock	Sufficient volume	0.9 - 1.0	0.8 - 1.0	0.8 - 1.0
	Marginal volume	0.5 - 0.8	0.4 - 0.7	0.4 - 0.7
	Marginal mature	0.3 - 0.6	0.2 - 0.5	0.2 - 0.5
Quality reduced source rock	Sufficient volume	0.7 - 0.9	0.6 - 0.8	0.6 - 0.8
	Marginal volume	0.4 - 0.6	0.3 - 0.6	0.3 - 0.6
	Marginal mature	0.2 - 0.5	0.1 - 0.4	0.1 - 0.4
Hypothetical source rock	Sufficient volume	0.5 - 0.8	0.4 - 0.7	0.4 - 0.7
	Marginal volume	0.3 - 0.7	0.3 - 0.6	0.3 - 0.6
	Marginal mature	0.1 - 0.4	0.1 - 0.4	0.1 - 0.4
Speculative source rock	Sufficient volume	0.4 - 0.7	0.3 - 0.7	0.3 - 0.7
	Marginal volume	0.2 - 0.6	0.2 - 0.5	0.2 - 0.5
	Marginal mature	0.1 - 0.4	0.1 - 0.3	0.1 - 0.3

Fig. 3.14 Probability scheme. The probability of effective source rock with respect to volume and maturity.

During risk assessment of potential source rocks, we must be aware that we perform risking on the basis of average values and not extremes. When we estimate the probability of sufficient volume mature source rock in the drainage area, we must also evaluate uncertainties in the definition and mapping of the drainage area. Large uncertainties in the mapping can have both positive and negative consequences for the anticipated hydrocarbon charge.

3.3.3.2 Effective migration

A critical factor that we must consider carefully is the relationship between the timing of migration and of trap formation. Here we must evaluate the probability of the trap being formed in due time to allow the accumulation of migrated hydrocarbons. We must assume that the trap is effective in terms of its sealing properties (with respect to both faults and cap rocks). It must be assumed that the trap has existed continuously from time of its

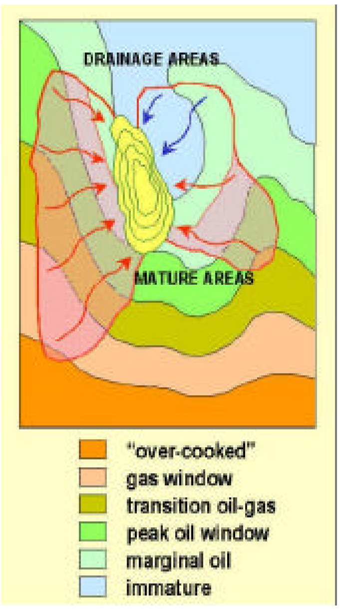


Fig. 3.15 Example of a maturity map with drainage areas and migration paths.

formation (i.e. P1 = 1.0 and P2b = 1.0). If seismic data alone does not provide an adequate basis to determine the time of trap formation, backstripping may be a useful approach.

It is important to note that evaluation of the petroleum charge system ends at the point in time of hydrocarbon accumulation in the sealed trap. This ensures that we avoid double risking of the probability factor related to retention after accumulation, P4.

Timing / Migration	The trap is formed before onset of hydrocarbon migration	Time of trap formation and time of migration are overlapping	The trap is formed when the source rock is supposed to be "overcooked"
Local migration	0.9 - 1.0	0.4 - 0.8	0.1 - 0.4
Lateral migration without barriers	0.8 - 0.9	0.4 - 0.7	0.1 - 0.3
Lateral migration with barriers	0.5 - 0.8	0.2 - 0.5	0.1 - 0.3
Vertical migration without barriers	0.7 - 0.9	0.3 - 0.6	0.1 - 0.3
Vertical migration with barriers	0.4 - 0.6	0.2 - 0.4	0.1 - 0.2
Long-distance "fill-spill" migration	0.4 - 0.6	0.2 - 0.4	0.1 - 0.2
The trap is in the "shadow" of migration	0.2 - 0.4	0.1 - 0.3	0.1

Fig. 3.16 Probability scheme. The probability of effective migration and timing.

Under normal pressure regimes hydrocarbons migrate upwards, and the migration mechanism can therefore be evaluated from maps (preferably depth maps) on which the direction of migration along the top of the carrier formation is perpendicular to the depth contours (fig. 3.15). Ideally, we should use paleomaps for this purpose, but such maps are not available in most cases. Migration may also occur along permeable fault zones and vertically by pressure equalisation. When evaluating potential migration mechanisms, we must also consider structural complexity, the dip of potential carrier formations, their lithologies, and the seal integrity at the upper surface of the carrier bed along the migration route. In general, gas exhibits a greater tendency than oil to exploit vertical migration routes (fig. 3.16).

Even in cases where we anticipate that the prognosed source rock is "overcooked" at the present day, we cannot eliminate the possibility that the trap is filled. Later tectonic movements may have caused the spillage of hydrocarbons from other traps into the trap under consideration ("fill-spill"). Uncertainties related to the possible presence of another source rock and our modelling must also be taken into consideration.

3.3.4 Retention after accumulation

The probability of effective retention of hydrocarbons in the prospect after accumulation, **P4**, is evaluated given the assumption that the sealed trap was filled with hydrocarbons at a given point in time. In order to evaluate this factor, we shall examine the course of events from the time of hydrocarbon accumulation to the present day.

Geological processes after accumulation / Data control		Positive unambiguous data (seismic, wells, etc.)	Data control and interpretation is poor to fair	Negative unambiguous data (seismic, wells, etc.)
No late activity	No tectonic activity after accumulation	0.9 - 1.0	0.8 - 1.0	0.7 - 1.0
	Shallow traps, possible biodegradation	0.8 - 0.9	0.4 - 0.7	0.1 - 0.3
Erosion	Trap in connection to generating source	0.7 - 0.9	0.3 - 0.6	0.1 - 0.3
	Trap not connected to generating source	0.5 - 0.8	0.2 - 0.5	0.1 - 0.2
Uplift and tilting	Form, volume, top-point not changed	0.7 - 0.9	0.4 - 0.7	0.2 - 0.4
	Form, volume, top-point changed	0.5 - 0.6	0.3 - 0.4	0.1 - 0.2
Reactivated faults	Compression and/or transpression	0.5 - 0.7	0.4 - 0.5	0.3 - 0.4
	Tension	0.4 - 0.6	0.3 - 0.4	0.1 - 0.3

Fig. 3.17 Probability scheme. The probability of effective retention.

We must assume that the caprocks at the time of accumulation had adequate sealing capacity to hold the minimum hydrocarbon column, and that all faults that delineate the trap are sealing. These factors have already been analysed as part of the risk evaluation of the trapping mechanism (P2).

CAUTION

In order to avoid "double-risking", we have to distinguish carefully between which factors affect the sealing mechanism and which affect retention after accumulation.

In considering the probability of effective retention, we must evaluate potential fault reactivation, regional uplift (and subsequent erosion), together with tectonic and/or isostatic tilting of the trap after accumulation. The guidelines are given in fig. 3.17.

A reconstruction of the post-accumulation history of the trap is an important factor in determining the hydrocarbon column and the anticipated hydrocarbon phase (oil or gas) in the prospect. It is therefore desirable to establish this history at an early stage in the risk assessment process, especially if post-accumulation events are anticipated to have had a significant influence on the prospect under evaluation.

Local or regional factors may significantly influence the assignment of this factor (i.e. fracturing of the cap rock, limited overburden). The pressure tolerance of the cap rock with respect to relative pressure differences between the cap rock and the reservoir rock may also be an important factor.

3.3.5 Hydrocarbon indicators

Certain anomalies identified on seismic reflection data can be caused by hydrocarbon-filled reservoirs. It may be useful to investigate such anomalies if we have reason to believe that they may provide direct evidence for the presence of hydrocarbons in our prospect. However, seismic anomalies may have many causes, both geological and geophysical, and some of the latter may be the result purely of acquisition and processing methods. A direct hydrocarbon indicator (DHI) on seismic data may be defined as follows:

> *A direct hydrocarbon indicator (DHI) is defined as a change in seismic reflection character (seismic anomaly) which is the direct result of the reservoir's fluid content changing from water to hydrocarbons.*

Depending on the cause of the seismic anomaly, it may be characterised as **real** or **false** in terms of its being a direct indicator of hydrocarbons (DHI). An anomaly resulting from an artefact caused by geophysical acquisition or processing is by definition a false DHI, while an anomaly resulting from geological causes may be either real or false.

Seismic anomalies should always be evaluated carefully with respect to their repeatability on adjacent 2D profiles. Various detailed studies of amplitude (e.g., amplitude versus offset, AVO) and phase may be useful in reducing uncertainty associated with seismic anomalies. We must also investigate whether the anomaly defines a trap, and whether other geological or geophysical causes other than the presence of hydrocarbons can explain the anomaly.

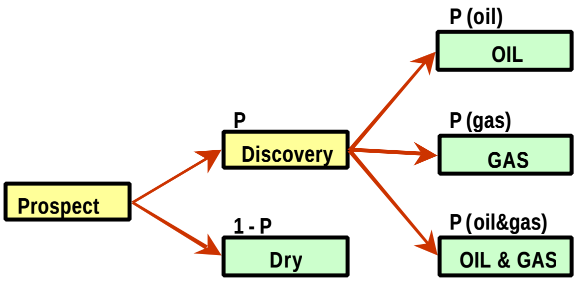
If we believe during the prospect interpretation and mapping process that we have identified a reliable hydrocarbon indicator, we may use information from the phenomenon as a basis for definition of some or all of the prospect parameters (rock volume, reservoir thickness, hydrocarbon column and phase, etc.). When performing the geological risk analysis, the DHI will be an important factor when considering the probability of effective trap (P2) and petroleum charge (P3).

Oil seepage, pockmarks at sea-bottom, gas anomalies in seismic data etc., are all indicators of hydrocarbons being present. Thus, this will skew the probability of having petroleum in the system towards the higher end. On the contrary, the probability of retention will be skewed towards the lower end.

3.3.6 Probabilities of oil or gas

When using modern prospect evaluation tools, such as GeoX, the proportion of oil and gas in our prospect is usually one of the input parameters in the volumetric calculation. However, in some cases we wish to evaluate different cases (oil-case, gas-case or a combination case). In these situations we must assess the risk associated with each case. In order to perform a correct risk assessment it is useful to draw up a “decision tree” as illustrated on the following page.

For any given prospect, the four possible outcomes (dry, oil, gas, oil & gas) are independent. The sum of their probabilities of occurrence is therefore equal to 1.0.



We will use an example of a prospect with a probability of discovery of 0.4. If, given discovery, there is 40% chance for oil, 30% for gas and 30% for oil and gas in combination, we can calculate the probability of any one of these events by multiplying by the probability of discovery. The result will be; P(oil) = 0.16, P(gas) = 0.12, P(oil&gas) = 0.12 and P(dry) = 0.60.

4. Conditional Probabilities

4.1 General introduction

In some cases we wish to estimate the total resource (or economic) potential of a group of prospects. This potential is best described by using a resource distribution combined with the probability of finding a minimum volume of resources or more. Let us look at an example. We have mapped 5 prospects, with probabilities of discovery equal to P_1, P_2, P_3, P_4, and P_5 respectively. If we assume that these prospects are independent (i.e. from different plays), then the results of drilling any one prospect will have no impact on the probabilities of making a discovery in the other four. Prior to any drilling activity, the probability of discovery in at least one prospect will therefore be:

$$P = 1 - ((1-P_1)\ (1-P_2)\ (1-P_3)\ (1-P_4)\ (1-P_5))$$

If all prospects have the same probability of discovery (50%), the probability of making at least one discovery will be 97%. On the one hand, this chance is very high, but on the other, the chance of making discoveries in all 5 prospects is very low, only 3%. This relation is valid only if the prospects are independent. If, however, the probability of making a discovery in these prospects is dependent on the result of drilling the first, then we must treat the probabilities in a different way.

Let us therefore assume that we have two events A and B, which are interdependent. The probability of event A is dependent on the result of event B, and this is written mathematically as P(A|B). As shown in the figure, the conditional probability of event A (conditional on event B) is equal to the joint (or shared) probability of A and B divided by the probability of B (the marginal probability). This relation is called the Bayes' equation or theorem, and forms the basis for our treatment of conditional probabilities in the following chapters.

BAYES' THEOREM

Conditional probability =

$$= \frac{\textbf{Joint probability}}{\textbf{Marginal probability}}$$

$$P(A|B) = \frac{P(A,B)}{P(B)}$$

Fig. 4.1 Bayes' theorem

4.2 Interdependency between prospects

Interdependency between prospects means that the result of the drilling of any one prospect (discovery or otherwise) will impact on the probability of making a discovery in all of the other prospects. In such cases, we must separate the probability factors into those which are common to all prospects (factor P(S)), and those which are independent (factors P(X|S)). The common probability factor may, for example, be a common unknown source rock, reservoir facies, etc. In this case, the probability of discovery in any given prospect X can be expressed as follows:

$$P(X) = P(S) \times P(X|S)$$

Let us illustrate this with an example. Assume that we have five interdependent prospects within a licensed area, and we wish to estimate the total resource potential. The probability factors for the five prospects are as indicated in the table in figure 4.3.

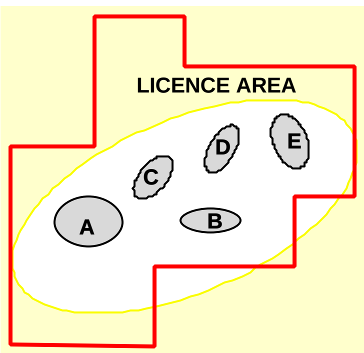


Fig. 4.2 Example of interdependent prospects

In this example, we define the common factor as consisting of the probabilities for reservoir facies, mature source rock and retention, and is equal to 0.8 x 0.7 x 1.0 = 0.56. It follows that the independent probability factors for each prospect will be the product of the factors for porosity, trap, seal and migration.

	Probability factors	A	B	C	D	E
P1a	Reservoir facies	0.8	0.8	0.8	0.8	0.8
P1b	Porosity	0.6	1.0	0.5	0.8	0.9
P2a	Trap identification	1.0	0.9	0.9	0.7	0.6
P2b	Seal	0.9	0.9	0.8	1.0	1.0
P3a	Mature source rock	0.7	0.7	0.7	0.7	0.7
P3b	Migration	1.0	0.8	0.9	0.8	0.8
P4	Retention	1.0	1.0	1.0	1.0	1.0
P(X)	**Individual probability:**	**0.3024**	**0.36288**	**0.18144**	**0.25088**	**0.24192**
P(S)	***Common factor:***	***0.56***	***0.56***	***0.56***	***0.56***	***0.56***
P(X|S)	*Other independent factors:*	*0.54*	*0.648*	*0.324*	*0.448*	*0.432*

Fig. 4.3 Partial probabilities of the prospects A, B, C, D and E as described in the text.

$$P(X|\bar{A}) = \frac{P(X|A) \times P(S) \times P(\bar{A}|S)}{P(\bar{A})} = \frac{P(X|A) \times P(S) \times (1 - P(A|S)}{1 - P(A)}$$

Fig. 4.4 Probability of discovery in X, given that A is dry.

If a discovery is made in A, the probability of making of discovery in B, C, D and E will be increased because the common probability factors have been confirmed. When we estimate the total resource potential in the area, the total will be equal to the sum of the risk-weighted non-drilled prospects that we derive by using the independent probability factors for B, C, D and E.. The amount discovered in A must be added to get the total resource potential for the licence.

If A is dry, there is still a chance of making a discovery in the other prospects since, prior to its being drilled, we do not know the reason for A being dry. We do not know if it is due to failure of one of the common factors or of one of the independent factors. If prospect A is dry, the probability of discovery in prospect X (i.e. B, C, D or E), may be expressed by the equation on the left, which is derived from Bayes' theorem and where;

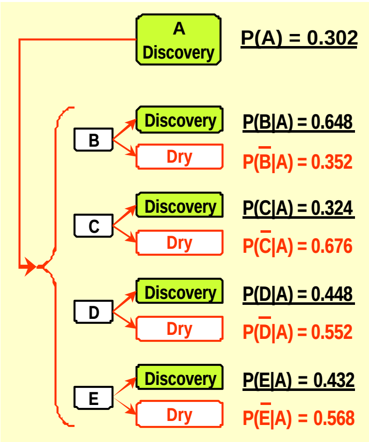


Fig. 4.5 Conditional probabilities in B, C, D and E, given a discovery in A.

In the example above we can now calculate the probabilities of discovery in B, C, D and E given that the A-prospect is dry:

P(X|A) = probability of discovery in prospect "X", given a discovery in ALPHA
P(S) = common probability factor
1 – P(A|S) = probability of ALPHA being dry, even though common factors work
1 – P(A) = probability of ALPHA being dry

Note that **P(Ā|S)** can be written as **1 – (A|S)** and that **P(Ā)** can be written as **1 – (A).** These are just two different ways of expressing the same relations.

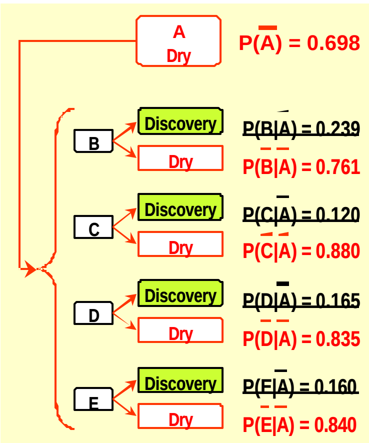


Fig. 4.6 Conditional probabilities in B, C, D and E, given that A is dry.

Probability of B, if A is dry;
P (B|Ā) = {0.648 x 0.56 x (1 – 0.54)} / (1 – 0.3024) = 0.239 (rounded)

Probability of C, if A is dry;
P (C|Ā) = {0.324 x 0.56 x (1 – 0.54)} / (1 – 0.3024) = 0.120 (rounded)

Probability of D, if A is dry;
P (D|Ā) = {0.448 x 0.56 x (1 – 0.54)} / (1 – 0.3024) = 0.165 (rounded)

Probability of E, if A is dry;
P (E|Ā) = {0.432 x 0.56 x (1 – 0.54)} / (1 – 0.3024} = 0.160 (rounded)

The conditional probabilities of discovery in the B-, C-, D- and E-prospects are illustrated in the decision trees in figures 4.5 and 4.6. In this case, the probability of making a discovery in A is P(A) = 0.302. Given a discovery in

A, the conditional probabilities of discovery in the other prospects are shown in figure 4.5. Given that A is dry, the conditional probabilities of discovery in the other prospects are shown in figure 4.6.

When we are estimating the total resource potential of the area, we use the conditional probabilities given a discovery in A. However, when we estimate the economic potential (i.e. “the expected monetary value”) we must also consider the conditional probabilities given that A is dry.

4.3 Multiple reservoirs

When we are dealing with multiple reservoirs (fig. 4.7), the interdependency between the reservoir levels can be treated in exactly the same way as for interdependent prospects.

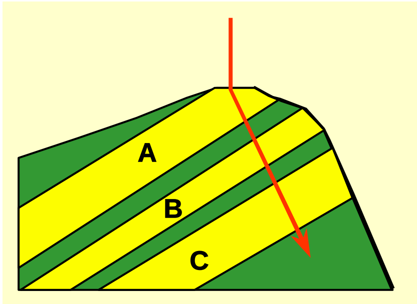


Fig. 4.7 Multiple reservoirs

Let us look at an example of a prospect with three reservoir levels; A, B and C, with the following assumptions.

$$P(B|\bar{A}) = \frac{P(B) - [P(A) \times P(B|A)]}{P(\bar{A})} = \frac{0.36 - (0.28 \times 0.9)}{1 - 0.28} = 0.150$$

Fig. 4.8 Probability of B, given A is dry

We are not sure if the A-reservoir is present. However, if the A-reservoir is present, and there is a discovery at that level, there is a very good chance of making a discovery in the B-reservoir and a reasonable chance of making a discovery in the C-reservoir. There is also a given chance of discovery in the B- and C-reservoirs, even if the A-reservoir is absent or dry. All other factors other than reservoir are common.

The usual methodology for risk assessment of individual *prospects* will give a probability for discovery in A of P(A) = 0.28. The chance of discovery in the B-reservoir is somewhat higher, P(B) = 0.36, because the probability of encountering reservoir B is greater than A. The conditional probability of discovery in the B-reservoir, given a discovery in A, is equal to 0.9. The common, or shared, factor P(S) will then be equal to 0.4.

$$P(C|\bar{A}) = \frac{P(C) - [P(A) \times P(C|A)]}{P(\bar{A})} = \frac{0.20 - (0.28 \times 0.5)}{1 - 0.28} = 0.083$$

Fig. 4.9 Probability of C, given A is dry

The individual chance of discovery in the C-reservoir is calculated to be P(C) = 0.20. The probability of discovery in the C-reservoir, given discovery in the A-reservoir P(C|A), will be P(C) / P(S) = 0.5.

In order to estimate the probability of discovery in the B- or C-reservoirs given that the A-reservoir is dry, the general equation as shown in figures 4.8 and 4.9 can be used.

Note that there are several alternative approaches to solve this problem. Try for example the alternative equation on the left (fig. 4.10), where the shared or common risk factor P(S) is introduced.

$$P(X|\bar{A}) = \frac{P(X|A) \times [P(S) - P(A)]}{P(\bar{A})}$$

Fig. 4.10 Alternative formula

5. Play Probabilities

5.1 General introduction

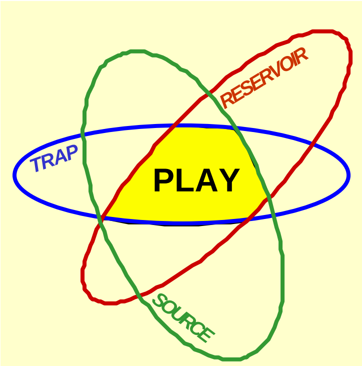


Figure 5.1 Schematic illustration of play definition

A play is defined as a group of prospects within a geographically delimited area, where a set of mutually related geological factors must be present concurrently in order to permit the discovery of hydrocarbons. The geological factors are typically reservoir rocks, traps, mature source rocks and migration paths, plus the condition that the traps were formed before the migration of hydrocarbons ceased. All fields, discoveries and prospects within the same play are characterized by the play's specific set of geological factors and can therefore be distinguished from the fields, discoveries and prospects belonging to other plays.

In play assessment we separate the probability factors described earlier into two groups; marginal play probability factors, and conditional prospect probability factors. The marginal play probability is common for all prospects in a given play and is hence similar to the product of the common probability factors as discussed in the chapter on interdependency between prospects. The conditional prospect probability is an average prospect attribute and is similar to the product of the independent probability factors discussed in the previous chapter.

5.2 Play delineation

In practice we face many challenges when attempting to define and delineate a play. These challenges are often due to lack of data control and/or inconclusive geological information. An assessment of whether we are dealing with mature, semi-mature or frontier areas also presents a challenge to play definition.

A useful approach to play definition is to prepare play maps for all those factors that are anticipated to define the play. Such maps may illustrate reservoir facies, porosity- and/or permeability changes, the presence and maturity of source rocks; areas of effective migration, effective traps and seals, together with areas favourable for effective retention of hydrocarbons. The main purpose of these maps is to illustrate where these factors are favourable or unfavourable to the success of the play.

Experience has shown that in some cases it is convenient to group together plays which exhibit large similarities, in particular in frontier areas where the plays are unconfirmed and the database is very limited. On the other hand, in mature and well-known areas with confirmed plays, it can be more useful to use the available data control and clearly defined criteria to distinguish between plays. In both cases, it is important to bear in mind that the purpose of defining distinct plays is to group mapped and unmapped prospects into manageable units which enable us to make as reliable an estimation of undiscovered resources as possible.

It is also important to consider the possibility of interdependency between plays. In some geological basins, there may be geological factors that are common to two or more plays. A typical example would be a regionally extensive source rock. If the plays are unconfirmed, there will be interdependency between all plays which share the same source rock. When assessing the undiscovered resources in a basin, interdependent plays must be treated in similar way to interdependent prospects with respect to their conditional probabilities, as discussed in chapter 4.

5.3 The play and prospect probability factors

Given that the play is properly defined (fig. 5.2), the common or shared geological probability factors for all mapped and unmapped prospects in the play will form part of this definition. The product of these factors is the marginal play probability, which is equal to 1.0 if the play is confirmed.

Individual probability factors defining the marginal play probability may differ between various plays. This will be related to local geological conditions. However, "rule-of-thumb" guidelines are given in the table below (fig. 5.3).

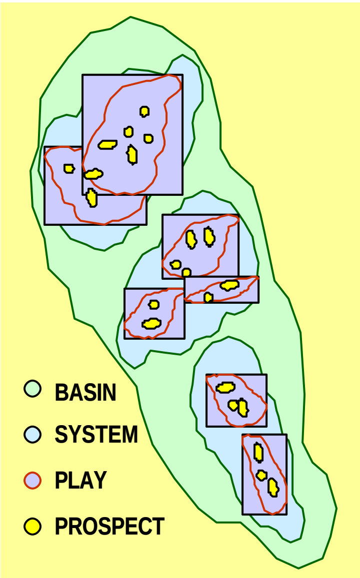


Fig. 5.2 Schematic illustration of the relation between basin, petroleum system, play and prospect

Probability factor	Marginal play probabilities	Conditional prospect probabilities	Comments
Reservoir	Reservoir facies	Effectiveness; porosity and permeability	Depends on continuity of reservoir facies
Trap	Sealing properties	Mapping quality and reliability	This subdivision may vary between different plays
Charge	Sufficient volume of mature source rock	Migration	Be aware of possible long distance migration
Retention	Retention		Unless local variations are identified

Fig. 5.3 Partial probabilities classified as marginal play probabilities and conditional prospect probabilities.

The conditional prospect probability is an average probability factor for all mapped and unmapped prospects for a given play. Clearly, some prospects within the play will have a higher probability, and some will have a lower probability, than the average value. For confirmed plays, the historical success ratio is an important guideline in determining of the average conditional prospect probability, although meaningful comparisons between plays must take the number of previously drilled prospects into account. A limited database may give misleading comparisons.

5.4 Independent petroleum systems

An independent petroleum system is defined as a continuous body of rocks separated from surrounding rocks by regional barriers to the lateral and vertical migration of liquids and gases (including hydrocarbons), and within which the processes of generation, accumulation, and preservation of oil and gas are essentially independent from those occurring in surrounding rocks (Ulmishek, 1986).

According to this definition, a petroleum system may contain one or more plays, the success of which may depend on others. The common geological factor in a petroleum system is typically the source rock, but other common factors may also occur. It is therefore crucial to define the petroleum systems within a basin when we are assessing the basin's total petroleum potential. It is also important to take the interdependency of plays into consideration when performing an aggregation of their resources.

6. Calibration of Probability Factors

As an aid to improve future exploration results, the post-drill evaluation of prospect risk assessment is an important activity. A detailed review of previous exploration results is necessary in order to identify which geological factors were not as successful as at first anticipated. Post-drill evaluations should form the basis of improved geological models, and in improved procedures for risk assessment for the play or basin under consideration. The calibration of probability factors by post-drill evaluation will also result in improved estimates of the remaining undiscovered resources. Such studies will provide input in answering the critical question; when should we stop exploration in a play or basin?

The drilling success ratio provides useful calibration of the average prospect probabilities in confirmed plays. The success ratio is by definition the ratio between the number of successes (discoveries) and the number of trials (wildcat wells). However, there are at least two important factors that should be taken into account when comparing success ratios and prospect probabilities:

1. It is crucial to define what is meant by "success". Many definitions of this term will be found, but for our purposes it is important that the definition is based entirely on geological criteria. *Geological success* should be defined as the discovery of the minimum volume (or more) as estimated in the prospect's volumetric calculation. Note that some companies and government institutions define geological success as the discovery of movable hydrocarbons, even if the volumes are too small to be economic (sometimes called "technical discoveries"). This definition cannot be used for the calibration of prospect probabilities. When the success ratio is used for calibration or for the comparison of prospect probabilities, it is critical that the number of successes is related to the defined minimum pool size in the prospect evaluation.

2. In plays which are confirmed with only a limited number of wildcat wells, the calculated success ratio is likely to overestimate the true value, since only the best and most obvious prospects will have been drilled. This can be adjusted by using the formula in the text box on the left (fig. 6.1). This formula assumes there are at least two more (unidentified) prospects in the play, of which one is dry. As the values of N and n increase, the two ratios (n+1)/(N+2) and n/N will converge.

$$\mathbf{SR} = \frac{\mathbf{n+1}}{\mathbf{N+2}}$$

where:
n = no of successes, and
N = no of trials

Fig. 6.1 Recommended formula for success ratio

Economic success is related to the discovery of commercial quantities of petroleum, and varies with changes in product prices and costs. Economic success should therefore not be used for the calibration of prospect probabilities.

The creaming curve (fig 6.2) is prepared by plotting the resource growth in a basin or play versus the number of wildcat wells. The curve indicates what we can expect in the future with respect to resource growth and field sizes. The curve is also a useful tool for calibrating the estimate of the remaining undiscovered resources.

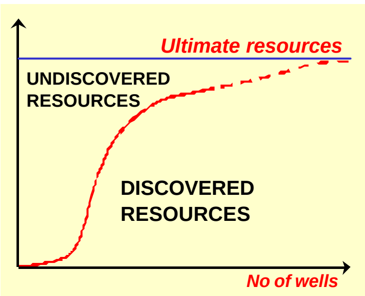


Fig. 6.2 The creaming curve (resource growth because of new discoveries)

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Units and conversion factors

In the petroleum industry quite a lot of different units have been used, and are in use, for measuring oil and gas quantities, distance, area and weight. This is sometimes very confusing even for technical people dealing with this kind of activities. We have therefore tried to summarise the most usual units and how to convert from one to another unit. Some caution should be paid when you are using the volume conversion factors, since they may have been measured at different physical conditions (pressure and temperature). The factors are picked from internationally published literature.

Distance

1 foot = 0.3048 meters
1 statute mile = 1,609 meters
1 nautical mile = 1,852 meters

Area

1 square mile = 640 acres = 2.59 square km
1 square km = 100 hectars
1 acre = 43,560 square feet
1 hectare = 2.471 acres

Volume

1 cubic meter = 35.3 cubic feet
1 cubic meter = 6.29 barrel
1 cubic meter = 1,000 litres
1 barrel = 159 litres
1 U.S gallon = 3.7854 litres
1 acre foot = 43,560 cubic feet

Weight

1 short ton = 0.907185 metric tons = 2000 pounds
1 long ton = 1.01605 metric tons = 2240 pounds
1 metric ton = 1,000 kilograms

Petroleum volumes and weights

This conversion depends on the density of the oil. In general, the density is in the range of 0.8-0.9 kilograms per cubic meter. By using an average density of 0.85, following conversions may be used:

1 (metric) ton of oil:	1.1765 cubic metres of oil
1 (metric) ton of oil:	7.4 barrels of oil

Energy conversions

One British Thermal Unit (Btu) is equal to the heat required to raise the temperature of one pound of water one degree Fahrenheit at or near its point of maximum density. This unit is commonly used to compare different energy sources.

1 barrel of crude oil =	5,800,000 Btu
1 cubic foot of dry natural gas =	1,032 Btu
1 short ton of bituminous coal =	26,200,000 Btu
1 kilowatt hour (kWh) of electricity =	3,412 Btu
1 gigajoule (10^9 J) =	947,820 Btu

Oil equivalents

Oil equivalents (abbreviated o.e.) are used for summation of oil-, gas- and NGL/condensate quantities. This term/unit is used to express the amount of energy that will be released upon combustion of the different types of petroleum. However, it is important to note that this measure is very inaccurate because of large variations in the composition of the various oils and gases. This term is used both for cubic meters (Sm^3 o.e.), tons (t.o.e.) and for barrels (BOE).

1000 Sm^3 of gas:	1 Sm^3 o.e.
1 Sm^3 of oil:	1 Sm^3 o.e.
1 ton of NGL/cond.:	approx. 1.3 Sm^3 o.e.
1 ton of oil:	1 t.o.e.
1 ton of oil:	1.1765 Sm^3 o.e.
1 barrel of oil:	1 BOE
1 Sm^3 o.e.:	6.29 BOE
1 t.o.e.:	approx. 7.4 BOE

Some commonly used abbreviations:

1 MBBL	= 1000 barrels
1 MMBBL	= 1 million barrels (10^6 barrels)
1 BCF	= 1 billion cubic feet (10^9 cu. feet)
1 TCF	= 1 trillion cubic feet (10^{12} cu. feet)

The Resource Evaluation and Planning Project (REP)

The resource Evaluation and Planning project (REP) is funded by the Norwegian Agency for Development Cooperation (NORAD) and started in January 1996. The project is the third major project within the petroleum sector that is funded by NORAD, namely Working Group on Resource Assessment (WGRA) in the period 1989 to 1991, Oil and Gas Resource Management (OGRM) in the period 1992 to 1994 and presently the REP-project that will be finalised in 1999.

The goal of the REP-project is to contribute to sustainable development of the petroleum sector in the CCOP member countries by providing governments with reliable information about their petroleum resources and value estimation. This should allow appropriate planning and management of petroleum exploration and exploitation, and thus in the long term be instrumental in providing higher revenue from the petroleum industry. The purpose of the project is:

- to transfer the know-how and technologies for quality ensured petroleum resource estimation in an economic context and hydrocarbon resource management options,
- to assist CCOP member countries in effective data management and establish resource management systems in individual CCOP member countries,
- to create the government awareness of the necessity of attracting external enterprises and establish realistic commercial expectations and priorities,
- to develop human resources in order to fill the gap between personnel and decision-makers in CCOP member countries.

The REP-project was divided in two phases. Phase 1 concerned basic training courses in petroleum geology and geophysics for the least developed countries in the CCOP-region, namely Cambodia, The Philippines and Vietnam. Thailand was also admitted to participate since they provided geological excursions. Phase 1 lasted for one year.

Phase 2, the main phase, comprise workshops and seminars with focus on resource evaluation, transfer of software tools, some bilateral seminars and training courses for nam and two working groups on petroleum resource classification and on exploration risk assessment. The current publication is a result of the first working group.

CCOP and NORAD are also discussing a future follow-up of the REP-project. Petroleum Policy and Management is the most probable theme for this follow-up activity.

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