DEVELOPMENTS IN PETROLEUM SCIENCE 20
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geology in petroleum production

A.J. DIKKERS

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Developments in Petroleum Science, 20

geology in petroleum production

a primer in production geology

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Van Soutelandelaan 45, 2597 EW The Hague, The Netherlands

ELSEVIER — Amsterdam — Oxford — New York — Tokyo 1985

ELSEVIER SCIENCE PUBLISHERS B.V.
1 Molenwerf
P.O. Box 211, 1000 AE Amsterdam, The Netherlands

Distributors for the United States and Canada:

ELSEVIER SCIENCE PUBLISHING COMPANY INC.
52, Vanderbilt Avenue
New York, NY 10017

Library of Congress Cataloging-in-Publication Data

Dikkers, A. J.
Geology in petroleum production.

(Developments in petroleum science ; 20)
Includes index.
1. Petroleum--Geology. I. Title. II. Series.
TN870.5.D535 1985 622'.3382 85-16151
ISBN 0-444-42450-4

ISBN 0-444-42450-4 (Vol. 20)
ISBN 0-444-41625-0 (Series)

Printed in The Netherlands

To Nans, who kept me going.

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PREFACE

This book, like so many of its kind, grew out of course notes; courses in applied oilfield geology, run over many years for varied audiences. At the end of a recent course, in the course review, one of the participants gave as his view: 'All this is no news, any geologist knows this'. Well, maybe so, but I have frequently, before and since, met geologists who, although having experience in the oil industry, proved to be unacquainted with at least some of the more common techniques applied in practical oilfield geology. Thus, finally, I came to the decision that it might be useful to put together – in what I hoped would be a convenient manner – those elementary but effective methods with which I was familiar during some thirty years of operational work.

I wish to emphasize that the resulting book is indeed intended as no more than a primer, as a basic introduction for the use of geologists, geophysicists, petroleum engineers and, perhaps, others involved in oilfield work. It makes no pretence to any degree of sophistication. Accordingly, no attempt is made to go to any depth into subjects closely related, such as log evaluation, seismic methods, sedimentology, computerization, etc.; excellent textbooks on such subjects are readily available.

The second part of the book's title may require some justification. During a lengthy career my job title has variously been: works-geologist, subsurface geologist, subsurface engineer, production geologist, geological engineer, development geologist. In my view the specialist under consideration is primarily a geologist; unlike most geologists in the oil industry he does not work 'on the exploration side' but 'on the production side'. Thus it would seem that the man is most unequivocally described as a production geologist and his discipline as 'Production Geology'.

'A true geologist speaks in pictures': the Professor of my undergraduate years, B.G. Escher*, is gratefully remembered by his students for the magnificent drawings – maps, sections, crystal shapes – that he used to make on the blackboard. From that tradition stems the 'comic strip' style of this book. Critics may object to my frequent use of fictional examples, rather than portrayals of actual geological conditions found in nature. Apart from the administrative and legal difficulties involved in collecting such evidence, it is rare that Mother Nature presents us with examples

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* Brother of the well-known graphic artist M.C. Escher.

which illustrate with satisfactory clarity the phenomenon that one wants to demonstrate. I can only hope that my pictures, although artificial, will help to achieve the objective of this book: to present to colleague-oilmen a ready-made set of tricks of the trade for their use in production geological work.

I gratefully acknowledge my indebtedness to the many teachers, colleagues and friends who, over many years, helped me to learn my job and to thoroughly enjoy doing it.

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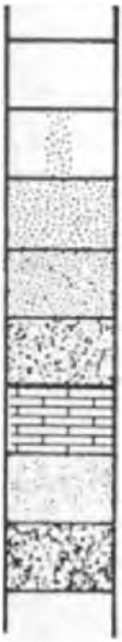
LEGEND

LITHOLOGY



clay - shale

sandy clay

sand: finer / coarser

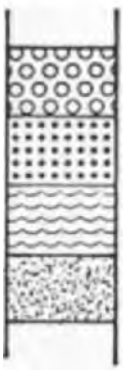
coarse sand - gravel

carbonate rock

impermeable ('tight') rock

igneous - metamorphic

RESERVOIR CONTENT



gas

oil

water

tar

Note: the same symbols are used on some maps.

FAULTS

fault in general

overthrust fault

ticks and triangles point to downthrown block.

WELL SYMBOLS

on field development maps

 oilwell, productive

 well with oil indications

 gaswell

 wet well

 injection well

 abandoned well

 location on programme

 grid location

on illustrative maps

 well in general

ABBREVIATIONS AND SYMBOLS

A.H.	along hole (depth)
API	American Petr. Inst. (gravity)
Bo	Formation Volume Factor (oil)
BDF	below derrick floor
BHP	bottom hole pressure
c.o.	cut-out (of fault)
D.F.El.	derrick floor elevation
DST	drillstem test
EOC	equivalent oil column
E&P	Exploration & Production
GOC	gas/oil contact
GOR	gas/oil ratio
G.R.	Gamma Ray (log)
H	high value
HCH	hydrocarbon column height
k	permeability
K.B.	kelly bushing
L	low value
M	medium (most likely) value
mD	milli-darcy
MSL	mean sea level
μ	viscosity
N/G	net over gross ratio
NGS	net gas sand
NOS	net oilsand
N.P.	not present
N.R.	not reached
OCH	oil column height
ODT	oil-down-to
OIP	oil-in-place
OWC	oil/water contact
P, p	pressure
Pcap	capillary pressure
Po	oil pressure
Pw	water pressure
P	probability
PED	Petroleum engineering Dep't.
proj	projected
PVT	pressure-volume-temperature
Ø	porosity
Q,q	production rate
Res.	Resistivity (log)
So	oil saturation
Sor	residual oil saturation
Sw	water saturation
Swc	irreducible water content
S.G.	specific gravity
ss	subsea (depth)
STOIIP	stock-tank oil initially in-place
SWS	sidewall samples
TD	total depth (final depth of well)
TVD	true vertical depth
V	volume
Vgr	gross volume
Vn	net volume
v.s.	vertical separation (of fault)
WUT	water-up-to

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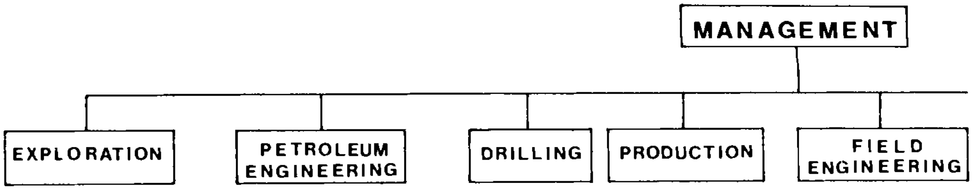
Chapter A

INTRODUCTION

A.1 ORGANIZATIONAL FRAMEWORK



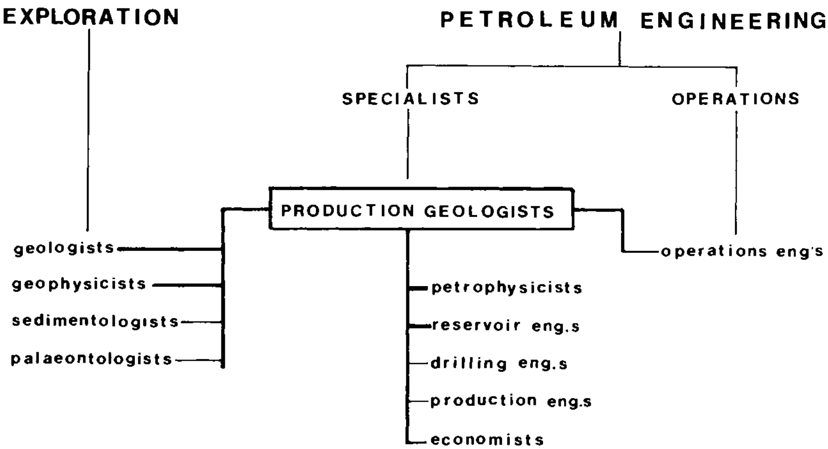
In the Preface it was pointed out that the production geologist does not work for the exploration department of his company, as do most of his fellow-geologists, but 'on the production side'. It is hoped that this book will show that this fact has a profound influence on his objectives, his working methods and his relationships to other members of his organization. Before starting on the description of the work of the production geologist, it may be useful to examine the position he occupies on the organization chart and to sketch the part he plays in the activities of his organization.

Companies engaged in exploration for and production of oil and gas – colloquially referred to as E-P or E&P companies – tend to be quite similar in their organizational structure, for obvious reasons.

Roughly speaking one can distinguish the technical/operational wing of the organization from the service and administration wing. Within the technical wing, sketched above, the various departments have their specific functions:

- *Exploration Department* carries out the search for accumulations of oil and gas.
- *Petroleum Engineering Department* is charged with the planning and functional supervision of – but generally not the line responsibility for – all operations required for the commercial production of hydrocarbons.
- *Drilling Department* is responsible for the drilling of the wells, in accordance with the general plans developed by the petroleum engineering department.
- *Production Department* carries out all operations to ensure the flow of the hydrocarbons from the reservoir through the well bore to the surface facilities.
- *Field Engineering Department* constructs and operates the surface facilities: drilling sites, roads, tanks, pipelines, pump stations, etc.

CONTACTS



In most E&P companies the production geologist is a member of the petroleum engineering department which consists of two groups of staff:

(a) the specialists, responsible for work in the various subdisciplines.

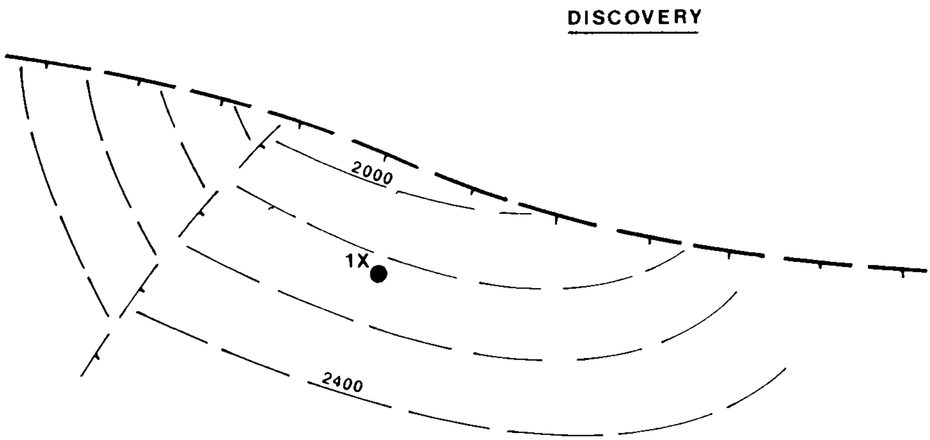
(b) the operations engineers, who maintain liaison with drilling and production departments.

The production geologist is a member of the specialists' group. His activities will be discussed in some detail in Section A.4; at this stage his relations with other members of the technical staff are examined.

His closest contacts are probably with the petrophysicists from whose interpretations of the logs run in the wells the production geologist derives much of his basic information. The reservoir engineer studies the physical processes which occur within the reservoirs as a consequence of the withdrawal of fluids during production; for these studies he needs the geological pictures of the reservoirs which the production geologist provides. The two specialists cooperate in the planning of the drilling and production operations in the field. Contact with the drilling and production engineers is less intensive. With the economics specialists the production geologist has frequent contacts, particularly because the planning of the drilling operations is not only controlled by technical considerations, but also has to conform to the demands of commercialism.

The production geologist is also in close contact with the exploration organization. From the exploration geologists he obtains his knowledge of the regional geological configuration against the background of which he constructs the geological picture of his oilfields. His dependence on the exploration department for geophysical information will be discussed in Section C.4. From the sedimentologists he may derive information for use in his studies in reservoir geology; palaeontological data may be of use in correlation problems.

A.2 OPERATIONAL FRAMEWORK



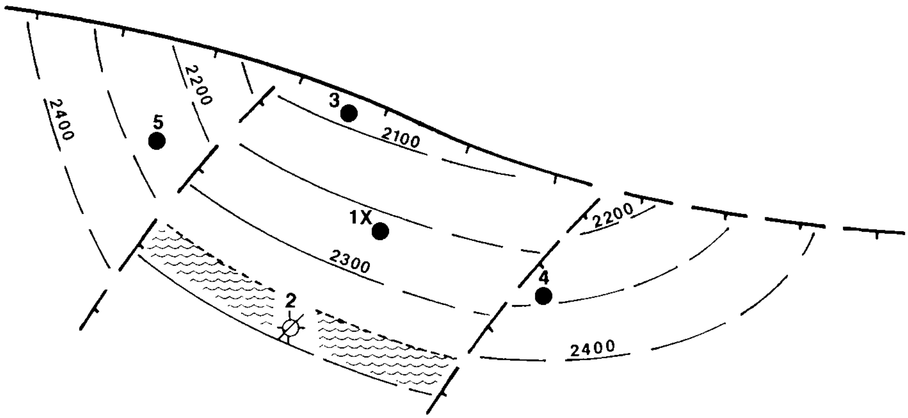
The main activity of petroleum engineering is the planning of the operations carried out to produce oil and gas from the underground reservoirs, generally referred to as field development. In clarification, the development history of a – fictional – oilfield will be sketched; from its birth as a successful exploration well to old age when, despite all technical efforts, the production rate of the field has declined below the economic limit and the field will be abandoned.

In current practice, a new field is generally discovered because a seismic survey has shown the existence of a structural configuration which could form a trap containing producible hydrocarbons. In order to test whether such an accumulation does indeed exist, an exploration well will be drilled. This is still essentially the responsibility of the exploration department: the location at which the well is to be drilled is selected by the exploration staff and they also determine such programme items as: depth to be reached; formation samples to be collected; logs to be run and tests to be carried out.

In the favourable case such a well penetrates one or more layers in which the presence of oil and/or gas is indicated by logs and formation samples. If the technical conditions in the well permit, tests will be carried out which are intended to give information on the possible production rate of future production wells.

The exploration well has now become a discovery well and the further development of the nascent oil- or gasfield becomes the responsibility of the petroleum engineering department.

APPRAISAL



The discovery well has produced affirmative answers to two all-important questions:

- Are any hydrocarbons present in the formations of the structure?
- Is it likely that wells to be drilled will be able to produce oil or gas at commercial rates?

The knowledge that producible oil or gas does indeed exist in the structure is, however, rarely sufficient basis on which to take the decision to invest the large sums of money which are required to develop a commercially viable field. The next important question is:

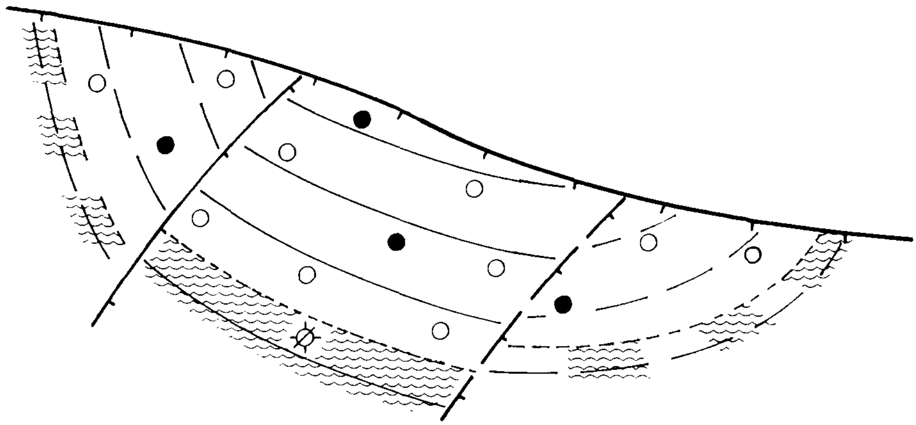
- How large are the quantities of oil or gas that can be produced from the structure?

In other words: required is an estimate of the reserves contained in the structure. For a reliable estimate the data available at this stage – i.e. a more or less vague seismic picture and the data from the discovery well – are rarely sufficient. In practically all cases it is necessary to drill a number of wells to obtain further information; such wells are called: appraisal wells or evaluation wells.

The illustration presents a map of the field after four such wells have been drilled; for explanation of symbols see p. xi. Three of the wells have found the reservoir formation oil-bearing, the fourth encountered only water. They have provided additional definition of the geology of the field: the position of the oil/water contact in the central block; the presence of a fault limiting this block to the east; presence of oil in the western and eastern blocks. Other questions still remain unanswered, especially as regards the structure and the position of the oil/water contact on these two blocks.

Nevertheless, for the purpose of this discussion, it is assumed that the information now available allows an estimate of reserves sufficient to support the decision to proceed with development of the field.

DEVELOPMENT PLAN



Once the decision to develop has been taken a development plan has to be prepared.

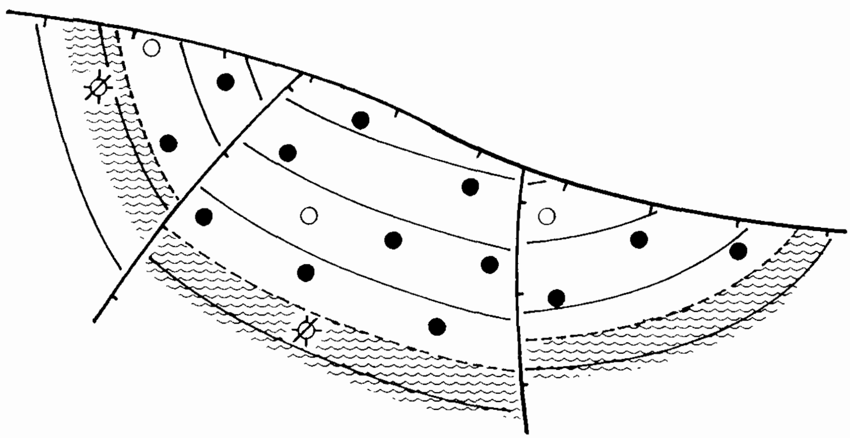
The main items upon which a decision is to be taken are:

- the number of production wells or 'drainage points' required
- the locations at which these wells are to be drilled.

The number of drainage points required to drain the reservoir properly is mainly a problem in reservoir engineering. Starting from the geological picture of the field provided by the production geologist, the reservoir engineer forms his opinion on such items as the quantity of oil or gas likely to be recoverable, the probable production rates of the wells, the likely behaviour of the reservoir fluids once production has started. From these estimates he decides – provisionally – on the number of drainage points required.

The likely behaviour of the reservoir fluids, or 'reservoir mechanism', also leads to a – global – preferred arrangement of the drainage points in the field area. The actual locations then have to be selected in a cooperative effort of production geologist and reservoir engineer. In establishing the details of the arrangement the geological structure has to be taken into account as well as possible and, also, the desirability of achieving a regular distribution of the drainage points over the productive area of the field.

DEVELOPMENT



The development plan is drawn up when it is felt that the appraisal wells have provided enough geological and other information on which to base the plan. However, the information at that early stage usually does not give a complete and reliable picture of the geological and technical situation. During the further development, as a result of the drilling of the production wells, additional data become available which often lead to changes in the geological picture which, in turn, may require modifications of the drilling plans.

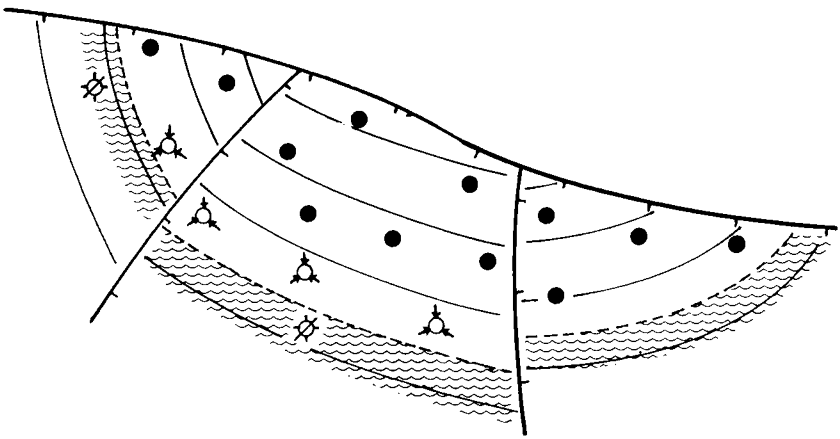
In the illustration the development campaign is supposed to be well advanced. The majority of the planned locations have been drilled; the original structural picture has been confirmed to a large extent. But two deviations from that picture have been found and require changes of plan.

In the western fault block the oil/water contact, which had, for want of better knowledge, been assumed to be at the same depth as in the central block, did in fact prove to be at a higher level. As a consequence the most downdip well in this block found the reservoir water-bearing and was abandoned. A replacement location farther updip has been inserted in the programme.

The fault between the central and eastern blocks proved to be in a different position. This required the inclusion of an additional location in the highest part of the block to provide drainage of this part.

The production data indicate that the number of drainage points in the central block is insufficient and an additional production well has been programmed. Such a well must be fitted into a space between previously drilled wells and is consequently often referred to as an infill well.

SUPPLEMENTAL RECOVERY

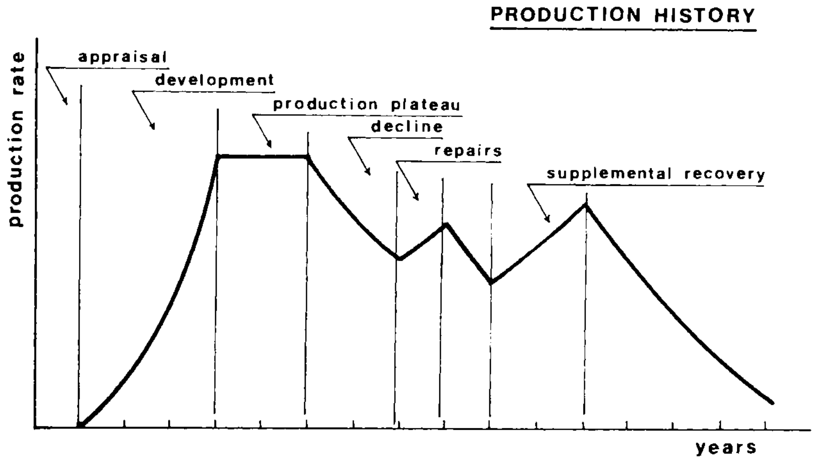


As the drilling of the development wells proceeds, the aggregate production from the wells already completed will increase, to reach a maximum when all wells foreseen have been drilled. As soon as no more new wells are added, the production from the field will tend to decline. If no further measures are taken, the production will decline to a level where the cost of field maintenance and production can no longer be met; the field has then reached its 'economic limit' and is likely to be abandoned.

In many cases the cause of the decline of the total field production rate is the fact that the pressure in the reservoir decreases because fluids are withdrawn in the course of production. Obviously, if this pressure decline could be stopped, or at least diminished, the decline of the field production rate would also be decreased and the field could then be kept on production economically for a longer time.

This consideration has led to the introduction of so-called 'secondary recovery' or 'supplemental recovery' techniques. The most obvious method to maintain the pressure in the reservoir is by injecting some fluid into the reservoir to replace the hydrocarbons removed; most commonly this injected fluid is water. Because water is heavier than the hydrocarbon mixtures in the reservoir, the most natural place to inject the water is in the lower part of the reservoir, i.e. in the vicinity of the oil/water contact. In the example above it will be seen that a number of wells in the central block, shown as oil producers on the previous maps, ae now indicated by the injection well symbol.

The examples of field development described in the foregoing paragraphs are no more than highly simplified outlines to serve as an introductory review. Many questions probably remain in the reader's mind; these may find an answer when the phases of field development are treated in more detail in Chapters G and H.

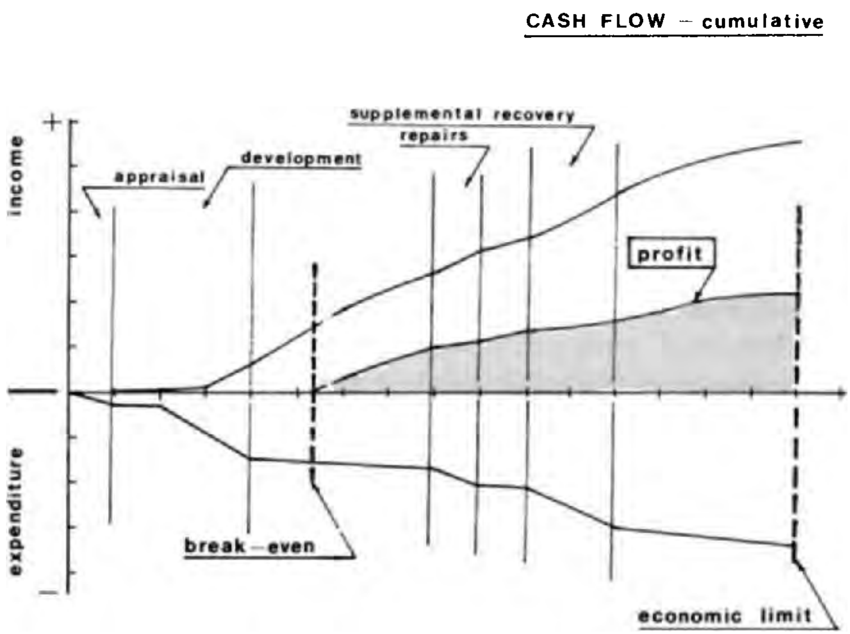


The purpose of field development is to produce hydrocarbons. The illustration above shows in a highly diagrammatic manner the development of the field production rate during – and as a consequence of – the various phases of the field development.

It was postulated that the decision to develop the field was not taken until the appraisal wells had provided sufficient encouraging information regarding the probable size of the accumulation. Once the decision has been taken, the necessary production wells will be drilled and the surface facilities, required for production, constructed. When the latter are ready for operation, the first actual production will be achieved and in the following period the production build-up will take place. When the majority of the producing wells has been drilled, it will generally be possible to maintain the production at a steady level or 'production plateau rate' for a certain time.

After some time, however, this will no longer be possible and the production decline will set in. This – as was stated in the previous paragraphs – is in many cases caused by pressure decline in the reservoir. Partly, however, the cause may also lie in deterioration of the mechanical condition of the production wells; it is often possible to correct this lack of effectiveness of the producing wells by repairs; these will then tend to arrest or at least diminish the production decline for some time.

A more effective way of combatting the decline may be – assuming suitable conditions prevail in the field – the institution of supplemental recovery operations, the simplest and most common being pressure maintenance by water injection. This will effectively offset the field decline, but eventually various negative influences will overtake the positive effects of the secondary recovery methods and the decline will again proceed.



An essential part of the operational background lies in the financial aspects of the field operations. It may be convenient to examine these in the form of the highly schematized income – expenditure – profit cumulative curves sketched above.

Expenditures start with the drilling of the appraisal wells. After a pause, for decision taking and preparation, the main build-up of moneys expended is caused by the drilling of the development wells. At some time during this development phase comes the start of production and, therewith, the beginning of income. In the first time thereafter the total of expenditures still exceeds the total income, i.e. no profit has been made. The phase of profit-making starts at the break-even point, the moment when cumulative income equals cumulative expenditure.

After the drilling of the development wells is completed, expenditure is essentially confined to operating costs, which are relatively small, as reflected in the low slope of the cumulative expenditure curve. In the later phases when the costs of repairs and supplemental recovery are added to the routine operating costs, this curve steepens again and the profit rate decreases.

In the final phases of the field's life, the production decline can no longer be prevented. Simultaneously the income curve flattens out, whereas operating costs continue, albeit at a low level. Eventually income and expenditure rates become the same and the profit rate consequently diminishes to zero. It is said that the economic limit of the field has been reached and consideration must be given to abandoning the operation.

A.3 THE FUNCTION OF THE PETROLEUM ENGINEERING DEPARTMENT

→ PLANNING → OBSERVATION → RECORDING → EVALUATION

feedback

Against the background of field operations as sketched in the preceding section, attention may now be given to the function of the petroleum engineering department in the organization which carries out these operations.

Oil production is a commercial activity and the purpose of the exercise is obviously to maximize profits. This means that efforts must be made to increase income, which in turn means increasing the quantities of oil recovered; by and large this can be achieved by drilling more wells. But on the other hand, the expenditures must be kept at the lowest possible level, which by and large means drilling fewer wells. These opposite demands must be reconciled in the actual field operations.

The factor time introduces a further complication: a certain amount of profit earned one year from now has a higher ('present-day') value than the same profit made ten years from now. Hence, in general terms, it is desirable to make the profits at the earliest possible stage in the life of the field. For instance, operations should be planned such that the time which elapses between the start of operations and the break-even point is as short as possible. Also, repairs and secondary recovery operations, apart from increasing the total amount of oil and thus of money to be made from the field, have the advantage of keeping the field production rate at a higher level; thus, instead of producing a part of this oil in a long 'tail' of the field decline curve, this same oil is now produced at an earlier date.

In order to achieve these objectives, the petroleum engineering department carries out its day-to-day activities, summarized in the figure above.

An outline of the *planning* phase has been sketched in Section A.2.

The drilling and production departments drill and 'produce' the wells in accordance with these plans, but it was emphasized in the section on field development (p. 6) that conditions are not always found to be in reality as they were thought to be at the time the plans were made. In order to determine whether such 'surprises' in the field conditions do indeed exist, the petroleum engineering department has to carry out a second function, here for the sake of convenience called '*observation*'. While the wells are being drilled and while production is in progress, information is collected on such aspects as: the characteristics of the formations drilled through; the depths at which various stratigraphic events are encountered in the wells; the rates at which oil, gas and water are produced; the variations in these rates with time; the pressure in the reservoir and its variations; etc., etc.

All this information has to be *recorded* in sufficient detail to be available for future reference. Petroleum engineering departments maintain comprehensive systems of reporting to meet this requirement: well reports; daily, weekly, monthly reports; production reports; etc.

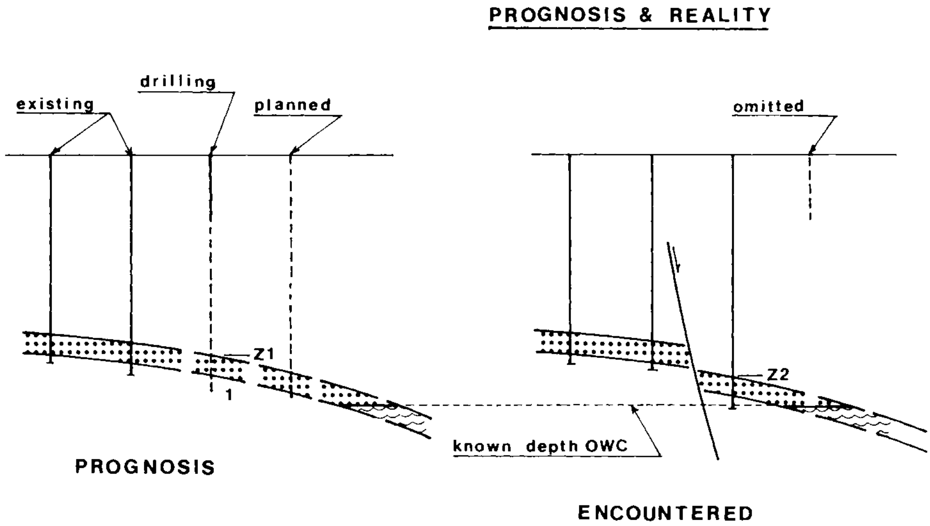
The information collected is then studied by the various specialists in the department in order to correct or update the existing picture of the field and of its production characteristics. In the figure this aspect has been named '*evaluation*' and examples of such evaluation have been given on p. 6.

It was already mentioned there that these differences between the original and the updated picture of the field are likely to lead to adaptations of the plans for further development. Thus there is in fact a *feedback* from the evaluation phase to the planning stage.

The figure on page 10 is intended to indicate that the separate phases of the activities of the petroleum engineering department are not actually separate but form a continuous cycle of: making plans; watching what happens when these plans are executed; using the information gathered to make the most suitable plan for the next step in the operation. This then requires day-to-day activity on the part of the petroleum engineers and calls for continuous watchfulness.

As this book is not a text-book on petroleum engineering, no attempt will be made to elaborate this brief sketch with more examples of a general nature. It is hoped that the remainder of the book will afford the reader opportunities to understand the function of the production geologist in this light.

A.4 THE FUNCTION OF THE PRODUCTION GEOLOGIST



From the sketchy account of the function of the petroleum engineering department in Section A.3 and from the fact that he is a member of this department, the task of the production geologist follows:

- he contributes from his special point of view to the optimization process for which the department is responsible;
- he takes part in the day-to-day activities of the department.

As an example of the everyday work of the production geologist the following brief – and fictional, but in practice quite common – story may serve:

A development well is being drilled in a field. In preparation the geologist has examined his maps and other documents and drawn up the well 'prognosis' (planning). This includes his expectation that the top of the reservoir will be reached at a depth Z-1.

From the examination of the rock samples recovered from the well while drilling, (observation) he concludes that the reservoir has not yet been penetrated when the well has reached this depth. Drilling continues and the samples indicate that the top of the reservoir is reached at the greater depth Z-2; logs, run subsequently, confirm this conclusion.

The geologist enters the new data on his maps and sections (recording).

Having considered various possible explanations of the deviation from the prognosis (evaluation), he concludes that the most likely interpretation is to postulate the existence of a hitherto unknown fault between the nearest previously drilled well and the drilling well.

This also means that the limit of the field – i.e. the position of the oil/water contact or edgewater limit – is actually much closer to the new well than was previously thought. In consequence, a programmed location for a further production well has to be removed from the plans, because it would find the reservoir mainly water-bearing and not be a productive well (feedback).

From this little history a fundamental demand on the production geologist can be formulated:

- he must maintain at all times *the best possible geological picture* of the field(s) for which he is responsible.

If he does not have this picture his evaluation of newly received data will not have a sufficient basis in properly digested previous facts.

With the construction and maintenance of this best possible picture his task is, however, not completed. It is not sufficient to turn over his picture to others in the department and leave them to draw the appropriate planning conclusions, in other words to leave the feedback phase to others. He should be sufficiently aware of what goes on in the developing field and ensure that his own geological conclusions are properly taken into account by the operators.

It may also be stressed here that nowhere in the foregoing discussions is there any mention of 'finding oil'. *Finding oil is not a primary objective for the production geologist,* as it is for the exploration geologist. The primary objective for the production geologist is to make his appropriate *contribution to the efficiency of the operations for recovering the oil that has already been found.*

Of course, if in the course of his studies he does discover additional reserves in his field, these will be very welcome (ref. Section H.7).

A.5 TERMINOLOGY

A major difficulty in discussing the activities of production geologists and their associates lies in the often distinctly unsystematic usage of various terms in oilfield practice. Many terms in everyday use are often applied in a much wider sense than is scientifically correct or even used to refer to concepts which officially cannot be described by that term at all. It is possible of course to use the terms only in their correct sense and to use other terms or circumlocutions for the other concepts. Whereas in the text of this book this will to some extent by attempted, it is often pedantic, inconvenient and even unnecessary to go to extremes in this matter.

A common example is the word 'oil' which officially refers only to liquid mixtures of hydrocarbons. If one describes the task of the production geologist as the cooperating in the optimal planning of the production of oil, this would strictly speaking exclude the production of gas. One could then write 'oil and/or gas', or 'hydrocarbons' – as has been done occasionally in the preceding pages – but this would be superfluous because the reader is probably well aware that the problems in gas production are quite similar to those in oil production, at least as far as the work of the geologist is concerned. Similarly, the term 'oilfield' is in many cases used to include also gas fields; just as the term 'oil industry' implies also gas industry in many cases.

Another often misused term is 'sand'. Obviously, this term is well defined in scientific geological usage. In the oilfield, however, it almost certainly includes also sandstones. And it may even be used to refer to permeable and thus potentially productive carbonate rocks. Similarly 'shale' is very commonly used for all argillaceous rocks, regardless of degree of consolidation and the presence of a shale texture.

The reader will in the following pages often find terms used loosely in this way. It is hoped that this has only been done where the colloquial usage could not cause confusion; where such confusion might result it has been attempted to use well-defined terms.

A.6 THE PLAN OF THE BOOK

Two aspects of the production geologist's task were set down in the previous section:

- maintaining the best possible geological picture of the field;
- ensuring that this information is properly used in planning the development of the field.

These two aspects are reflected in the plan of the book.

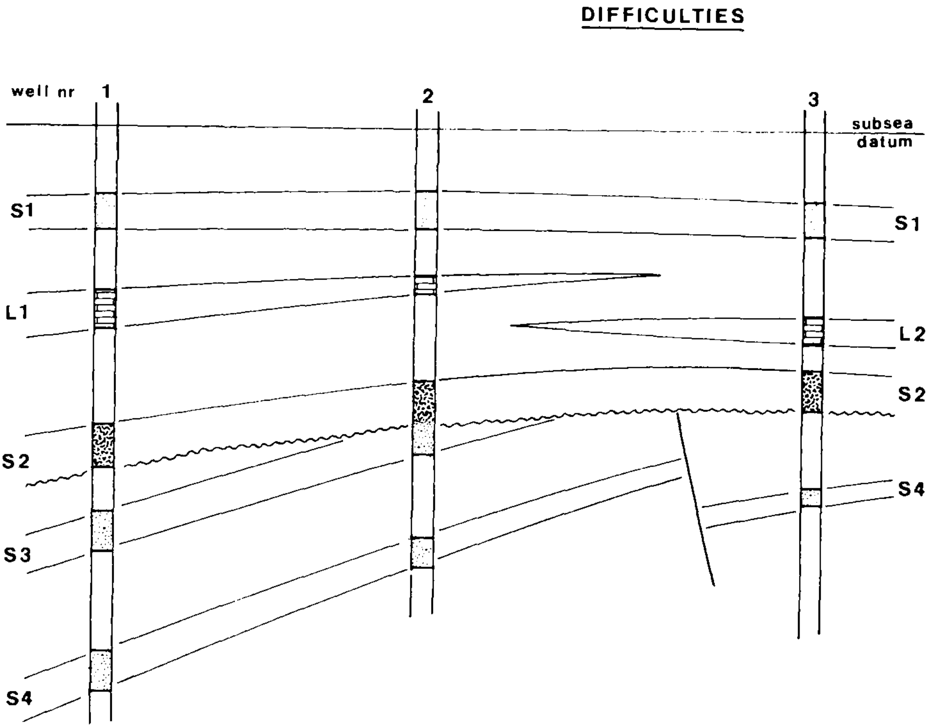
Chapters B-F describe the techniques the geologist applies in constructing his image of the field. A complete field study can be subdivided into a number of stages, starting from the raw data and ending with the comprehensive geological description. The first part of the text discusses these stages in their logical order.

The later Chapters deal with the application of the production geologist's stock of information and specialized knowledge in the development of the field. The successive stages in a field's development history, already briefly outlined in Section A.2, will be dealt with in full in Chapters G-J.

Chapter B

CORRELATION

B.1 PRINCIPLES



Correlation is fundamental to all production geological work; without correlation no effective work is possible. Unfortunately, a good definition, or even a clear description, of the process is difficult to give.

The diagram above may help to clarify this statement. It shows a section through a stratigraphic situation; this situation has been 'sampled' by three wells. The data from the wells show sandstone and carbonate layers interbedded in shale. The task of the production geologist is to reconstruct the entire situation, having only the rather meagre sampling of information available.

It is obvious that, starting from the three well intervals shown, the reconstruction means that lines have to appear in the section connecting those beds in the three wells which are the same. The first step is to decide which of the beds penetrated in the three wells are indeed 'the same'; in other words the operation is a process of identification and it is called 'correlation'.

Any process of identification requires criteria on which the identification can be based and it is here that the fundamental difficulties of the correlation process appear. The layers found in the wells have various characteristics which, one would think, could be used as identification criteria.

One of those characteristics is bed thickness, but any geologist who has ever followed a layer in the field knows that bed thickness is so variable that it cannot, by itself, be a suitable identification criterion. In the section, limestone L1 and sandstone S4 do not have the same thickness in the three wells, but the figure shows that it is correct to correlate the corresponding intervals.

Lithological similarity is not universally applicable either. It works properly for sandstone S2: a coarse sandstone in all three wells. But limestone L1 in wells 1 and 2 is similar to L2 in well 3, but the three intervals do not belong to the same limestone layer. Conversely, sandy layer S1 is the same in the three wells but is not lithologically uniform.

Stratigraphic position is not a reliable criterion either. In all three wells one limestone bed was penetrated between sands S1 and S2, but it is not the same limestone bed in all three. Similarly, in well 1 the first sandstone below S2 is sandstone S3, but in well 3 it is layer S4.

It is hoped that the following sections of this chapter will make clear how these and other difficulties are handled in the practice of oilfield correlation work.

B.2 SOURCES OF DATA

Correlation, then, is the mutual identification of layers – or groups of layers – penetrated in the various wells in a field and it is useful therefore to consider what information the wells provide on which the comparison of the various intervals can be based.

In regional geology such comparisons are often possible on the basis of fossil content of the formations, in other words by palaeontology and palynology. In the practice of oilfield work this is not often possible. For one thing, the analyses required are generally laborious and time-consuming, which is a disadvantage in oilfield development, where quick answers generally have to be provided. Moreover, in regional work it is usually sufficient to correlate relatively thick intervals, say, Formations, whereas in oilfield work correlation often has to be carried down to individual layers and the resolving power of palaeontological and palynological stratification is frequently not sufficient for work on this detailed scale.

In consequence, the only basis for the comparison of intervals in different wells that remains in practice, is the *lithology* of the rocks constituting these intervals. In other words, correlation in the oilfield is an exercise in comparative lithology. It may be obvious to the reader that modern sedimentology therefore has greatly helped in improving the quality of these exercises. It should also be clear that *all information* on the lithology of the rocks, which can be extracted from the data gathered in the wells, must be used.

The most direct way of obtaining knowledge about the lithology of the rocks drilled through would obviously be to collect actual samples of the rocks; three types of such samples may be considered:

Ditch samples (drill cuttings, cutting samples) are samples of the rock material broken off by the drillbit and brought to the surface by the circulating mudstream. They have the advantages of being cheap, continuous over the section drilled and obtained with very little delay while the well is being drilled, and thus available for immediate inspection. Their main disadvantage is that they are not necessarily very well representative of the formation drilled through. First, because some formations (chalks, soft clays, loose sands) tend to disintegrate in the mud and thus may be lost, largely or entirely. Secondly, because the samples are often contaminated by rock material fallen from the wall of the hole above the interval just drilled ('caving').

Sidewall samples are small, cylindrical (1 × 2 inches) samples taken from the wall of the hole by means of a 'gun' run on the cable also used for logging the well. They have the advantage of being taken after the well has been logged, which allows exact selection of the layers to be sampled. Also they can be very accurately located and are essentially free of contamination; therefore they are *generally* quite representative of the layer sampled. Disadvantages are: the small dimensions and the fact that they only become available a long time after the well interval has been drilled and are thus not suitable for day-to-day observation of the progress of the well.

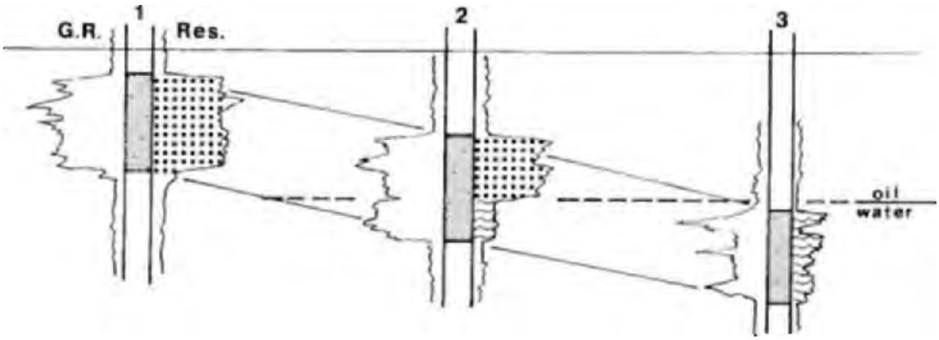
Cores are large formation samples: several inches in diameter (dependent on the size of hole being drilled) and up to several tens of feet long. They have the obvious main advantage of their large size, which affords a magnificent opportunity for comprehensive study of the rock material. Also, the depth of origin of this material is generally accurately known. Except in cases where the recovery is low, say, where out of a core of 10 metres only 2 metres are recovered and it cannot be known exactly where in the ten metres of interval the two metres of material actually came from. However, coring is a very time-consuming operation, often not devoid of danger for the drillhole, and thus is expensive. In practice it should therefore only be applied if a very accurate prognosis can be made of the depth at which the interval to be cored can be expected. If this cannot be done with sufficient reliability there is a fair chance that only formations of no interest will be recovered, which is an obvious loss of money.

In everyday practice of oilfield development drilling, cores will be taken very rarely because the high costs can rarely be justified. Sidewall samples may be taken to solve specific correlation problems, but more frequently to obtain information on the characteristics of a reservoir rock. Ditch sampling is routine in many fields and the production geologist is required to ensure accurate description of the samples (which may be entrusted to a service company in suitable conditions); in fields where the geological structure is quite simple, even ditch sampling may be omitted in routine wells.

Nowadays the most important source of lithological information for correlation purposes is provided by *petrophysical logs,* i.e. continuous measurements of physical parameters in the borehole which reflect characteristics of the formations through which the hole was drilled. These logs are produced by sophisticated instruments, run on a cable, and their interpretation in terms of lithology, fluid content, etc. has developed into a major subdiscipline of petroleum engineering.

Logs have the enormous advantage of being continuous with a very good resolving power: beds of about one metre thickness can generally be identified; also the depth determination is very accurate. A restriction on their usefulness is that they can only be taken after a section of hole has been drilled and the logging operation interrupts the drilling for considerable periods and is therefore a major cost item. Hence, and particularly in field development drilling, logging runs will be kept to a minimum and correlations based on logs can only be made after the section of hole has been drilled. Only in particularly critical cases will a 'correlation log' be run exclusively to determine which stratigraphical level the well has reached at that moment.

LOG EFFECT



For the great majority of production geological studies, logs are by far the most important, if not the only, source of data on lithology for the correlation phase of the study. How the logs are used will be discussed in the following Sections, but two aspects must be brought forward here:

- All logs reflect lithology – to a greater or lesser extent; therefore, as correlation is based on comparison of lithology, all logs must be considered as potential sources of data for correlation purposes.
- In practically all logs the effects of lithology are obscured to some extent by other effects and care must be taken to base correlation conclusions only on the indicators of lithology.

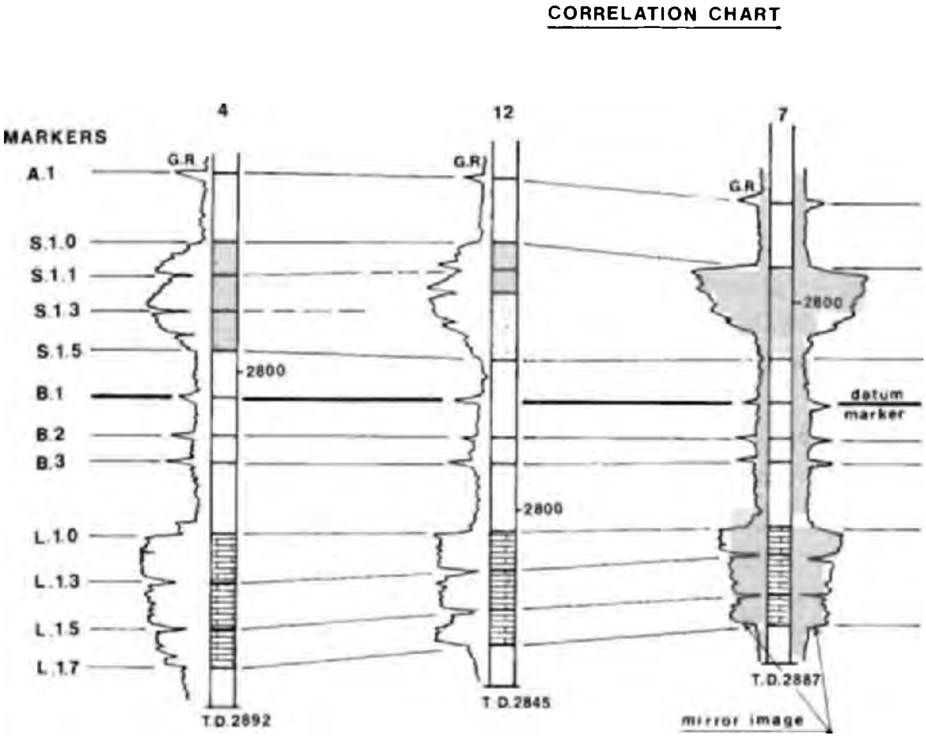
The sketch above may clarify the latter statement. In general the resistivity log, shown conventionally on the right-hand side of the log centre column, distinguishes quite well between shale, with relatively low resistivity, and sandstones. The resistivity of the latter, however, is to a large extent dependent on the composition of the fluid contained in the pores of the rock. Thus a sandstone interval penetrated by a well may have essentially uniform lithological characteristics from top to bottom, but the resistivity will be by no means uniform if the layer contains oil in its upper part and salt water in the lower part (well 2). Similarly, the same sandstone layer may be oil-bearing in one well and salt-water-bearing in another: the log appearance will then be quite different in the two wells and in consequence, correlation of the logs of the various wells will be more difficult (comp. wells 1 and 3).

In most cases the log that most clearly reflects lithology, with least interference from other effects, is the gamma ray log (to the left of the centre column). This log measures the natural radioactivity of the rocks. Clay minerals tend to be more radioactive than quartz and carbonate minerals; in consequence, rocks with different content of argillaceous material will show up clearly as layers with different deflections on the gamma ray log.

The so-called spontaneous potential, generated in the hole by differences in salt content between drilling mud and formation fluids, was the very first physical parameter to be used in well-logging. It often shows a picture which reflects lithology in much the same manner as the gamma ray log. The 'S.P.' log therefore was frequently used as a correlation log, but it is rarely run at present because of inherent inaccuracies.

It is important to emphasize here again that it is rarely sufficient to consider one log only for correlation. It is generally imperative to check the correlation obtained from comparison of one type of log, for instance the gamma ray, by also comparing other logs over the same intervals of the various wells; by doing this, possible errors can often be avoided.

For convenience – and it is hoped also for clarity – only a schematic gamma ray log is used in the sketches accompanying this chapter.



The lithology of rocks drilled through is reflected on the logs because physical properties of the rocks cause variations in the deflections of the log curves. In consequence, the comparison of lithology, on which correlation was said to be based, is replaced by a comparison of the shapes of log curves. Correlation is considered to be established, if comparison of the logs of two wells shows intervals with sufficient similarity of the log shapes. How strong a similarity can be considered 'sufficient' is largely a matter of experience, both general and local. (The use of log shapes for genetic study of sediments will be discussed in Chapter D).

In the practice of oilfield correlation work, one starts with copies of logs of individual wells. These one puts side-by-side and moves with respect to one another until sections of log with convincing similarity are found. The process is often easier if transparant copies of the logs are used, which can be superimposed on each other. Also, in many cases it is not very convenient to use the logs as they are delivered by the logging company, because the actual log curves are often obscured by the superposition of different log types and of other information. In those cases it may be advisable to trace off the lithologically most informative curve and use this, certainly for the initial phases of the correlation procedure. In difficult cases it may be helpful to 'mirror-image' the log, as has been done for illustration purposes for well 7 in the figure above.

Once the main lines of the correlation have been defined, i.e. the major correlatable intervals, such as the sandstone and limestone intervals in the example, have been recognized, it is usually advisable to prepare a *correlation chart* (often, though less correctly, called stratigraphic section). On this diagram, usually a large sheet of paper with lengths of log stuck on, further details of the correlation can be established, for instance the correlation within the main sand and carbonate bodies in the example. Moreover, the adopted correlations are clearly recorded, which is useful for future reference and for demonstration purposes.

Similar-looking diagrams consisting of sections of well logs arranged on a sheet are also used for other purposes: as structural sections for work in tectonics (Chapter C) and as penetration charts for accumulation analysis (Chapter F). However, the construction of these diagrams is different from that of the correlation chart: on the correlation chart the log sections are:
- lined-up on a stratigraphic datum;
- arranged in a sequence which will best illustrate the stratigraphic variations;
- spaced in a convenient way but not necessarily exactly to scale.

A useful tool for log comparison is also the *type log*: this is an artificially composed log, made up of log sections from different wells. The purpose is to have available a log which shows the complete stratigraphic sequence of the field. For each correlatable interval that well log is chosen which shows the characteristic shape of the interval most clearly. The type log is particularly useful if the wells in the field show many fault gaps (compare Section B.5)

When the correlation exercise has led to the recognition of a set of correlatable intervals, these units must be given names for purposes of recording and communication, just as in regional stratigraphy formations and members are identified by formal names. In oilfield practice a system of *markers* is introduced. Markers, in this context, are stratigraphic planes which can be reliably recognized over all, or a great part, of the field area. On the correlation charts these marker planes naturally appear as lines, as shown in the figure. A convenient system of nomenclature is designed, usually a combination of letters and numbers. The system must have sufficient flexibility to allow changes and additions, if such prove necessary as field development proceeds.

CORRELATION TABLE

WELL Nr.	4	7	12	15 (deviated)		
D.F.Elevation	123	119	127	138		
				A.H.	T.V.D.	
Top Eocene	2743	2754	2700	2909	2790	
A.1	2766	2778	2725	2936	2814	
S.1.0	2781	2793	2740	2954	2829	
S.1.1	2790	N.P.	2747 ?	2965	2839	
S.1.3	2798	N.P.	?	2975	2848	
S.1.5	2807	2815	2768	2986	2857	
B.1	2818	2826	2778	3000	2869	
B.2	2827	2834	2787	faulted	faulted	
B.3	2834	2839	2793	3007	2876	
L.1.0	2851	2855	2809	3027	2893	
L.1.3	2862	2861	2818	N.R.	N.R.	
L.1.5	2873	2871	2827			
Total Depth	2892	2887	2845	3032	2898	

All depths in metres B.D.F.
A.H. - along hole **N.P. - not present**
T.V.D. - true vertical depth **N.R. - not reached**

Finally, a *correlation table* is prepared in which the correlation as established is recorded in alphanumerical form for ease of reference, especially in later mapping work. A simple example of such a tabulation is shown above.

The main body of recorded information consists of the depths at which markers were encountered in the wells under study.

A choice must be made on the type of depth figure to be recorded. The most easily available is the 'well depth' (= drilled depth or along-hole depth), which can be read directly from the log. It is also the depth used by drillers and production staff and is therefore the least likely to lead to confusion in everyday oilfield work. This depth is measured during drilling and logging from a reference mark at the surface. This is usually the derrick floor (as in the example above) and depths are then referred to as 'below derrick floor' or B.D.F.; another frequently used reference is the kelly bushing.

However, for geological mapping work the depths below a common horizontal datum plane have to be used. The most commonly adopted reference level is Mean Sea Level and the depths below this level are referred to as subsea depth:

well depth − derrick floor elevation = subsea depth

Normally the well depth and the D.F.elevation can be read directly from the correlation table and the subsea depths then entered on the work maps.

This simple operation for deriving subsea depth is applicable only in vertical (or very nearly vertical, i.e. not intentionally deviated) wells. Nowadays, especially in offshore work, deviated wells are very common. For these wells the depths used in mapping cannot be directly derived from the well depth and elevation. The depth must be corrected for the hole deviation and is then referred to as the true vertical depth or TVD. The correction is carried out by means of the deviation survey. Such a survey is part of the standard logging package in deviated wells and the computation of the corrected depths is normally done by the logging company with the help of the computer. Various computer programmes may be used for the purpose, applying somewhat different systems, and the production geologist will be well advised to acquaint himself with the system used for his data.

The above sample of a correlation table is of course quite simple. It will be clear that additional data, such as unconformities, faults, thickness between markers, can be added, as convenient to the user. It is also obvious that the correlation table is an ideal document for computerization, especially in fields with large numbers of wells, many of which may be deviated (so that it will be advisable to have tables of both well depth and TVD available), and with elaborate stratigraphic information.

B.4 PROCEDURE

Correlation is an indispensable first step in production geological work and the preceding section has sketched the techniques applied in the recognition, the illustration and the recording of correlatable levels, markers, layers, units, etc.

It may be useful, however, to point out that not all correlatable events need be identified and recorded. For one thing, many oilfields are overlain by a thick overburden which is essentially flat or at least shows very little structural relief. Maybe several tens of markers could be established in such a section, but it will be obvious that the selection of only a few markers, perhaps one every few hundred metres, is sufficient for purposes of control. A detailed correlation with closely spaced markers will be necessary only in those intervals where the tectonic structure is complex. As a general rule: the degree of refinement of the correlation is to be adapted to the intricacy of the geological situation under study.

Furthermore, the correlation procedure will depend to some extent on the purpose for which the correlation data are principally to be used.

The study of tectonics (= structural geology) in an oilfield, is concerned with the deformations to which the rocks in the field have been subjected in the course of geologic time, since their deposition (compare Chapter C). It would seem to be evident that the study of these deformations can best be carried out on levels (beds, layers) which were originally, i.e. at the time of deposition, essentially flat and horizontal. The deviations from this flat and horizontal position, which these beds show at the present time, must then be caused by tectonic deformation exclusively. Thus markers that are to be used mainly for purposes of structural analysis should represent such beds as may be expected to have been flat and horizontal originally.

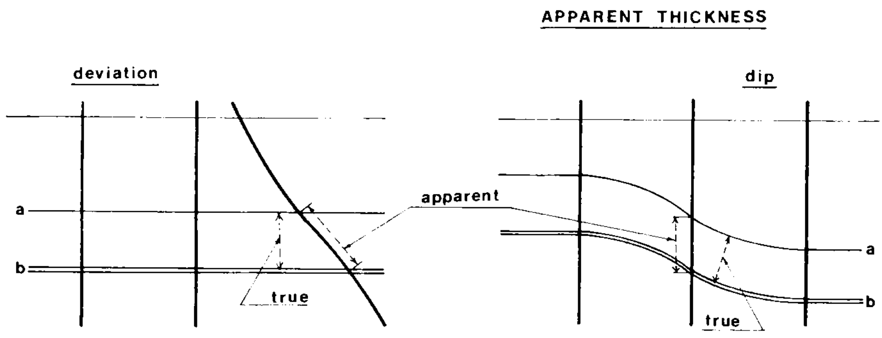
Such beds are to be found most probably in formations which were deposited in low-energy environments (Chapter D); such environments mostly produce argillaceous sediments. On logs these often appear as featureless 'tramline' curves, but closer examination will in many cases reveal small sharp deflections or peaks in the otherwise monotonous interval. Experience has shown that such small peaks are often very useful for use as markers in structural work; examples are shown at markers A.1 and B.1, B.2 and B.3 on the correlation chart (p. 22).

Other planes of significance in tectonics are: unconformity planes and fault planes; both can often be located in the wells by careful correlation, as described in the next section. It may be convenient to record in the correlation tables the depths at which such planes are found.

Rather different problems are encountered in correlation work done for the purpose of sedimentological analysis. As will be discussed in Chapter D, such sedimentological studies are mostly required for the detailed description of rock bodies which form hydrocarbon reservoirs. The questions to be answered are concerned with the continuity of individual sedimentary units within the reservoirs, in order to map the extent and thickness variations of these units and to form an idea of the likely flowpaths for the reservoir fluids.

Correlation for this purpose, then, must be directed towards the recognition and identification of such sedimentary units within the reservoir zone. By nature reservoir rocks are coarse-grained in the majority and mostly products of high-energy environments of deposition; for example, channel sands, coastal barrier sands. In consequence, the correlation work is likely to be complicated by the frequent lateral discontinuities and marked lateral variations in thickness and other characteristics of the rock bodies, much more so than in correlation for structural work. These irregularities will also affect the design of the marker and nomenclature system. Moreover, because reservoir formations are rarely more than a few tens of metres thick, the spacing of the markers will be much smaller.

B.5 COMPLICATING CONDITIONS

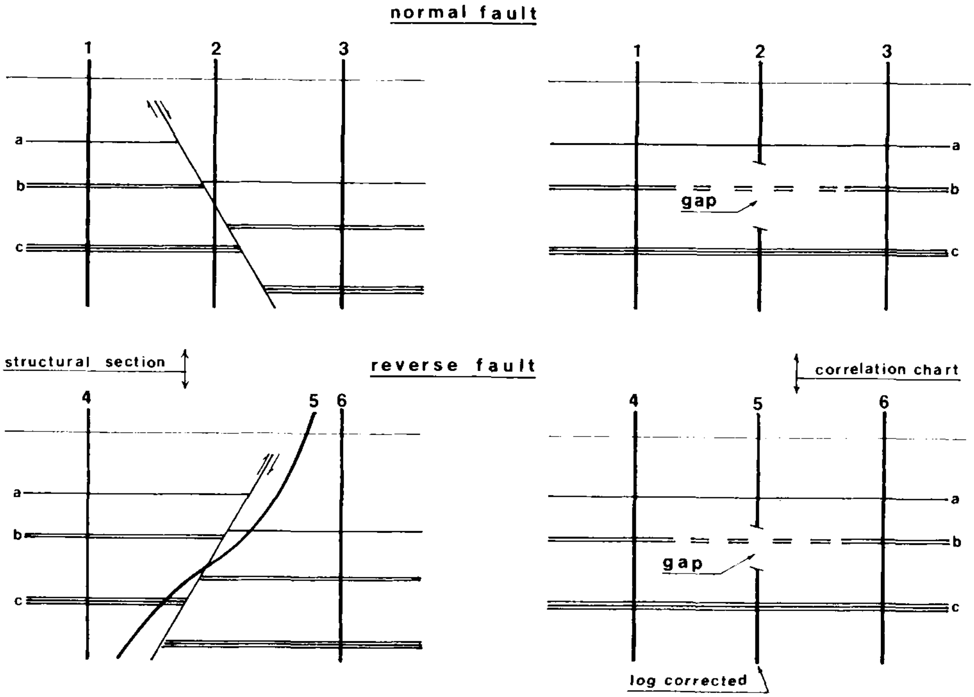


It may be useful to draw attention to some of the conditions which in practice can complicate the correlation process and may lead the unwary worker into pitfalls.

A vexing complication arises in cases where the log run in a well does not represent the true stratigraphic thickness of the penetrated beds, but a different, apparent thickness. This occurs whenever a strongly deviated well is drilled. The section on the left above shows how the distance between two markers 'along hole' is larger than the true thickness found in the vertical wells. As, especially in offshore fields, many wells are deviated over considerable angles, this condition occurs frequently. A deviation angle of 45° is not at all uncommon and results in a lengthening of 40% over true thickness. It will be obvious that logs obtained in such wells cannot be correlated with those of vertical wells by immediate comparison. This difficulty can be overcome by correcting the log to the true thickness values in accordance with the deviation angles measured in the deviation survey; as logs are commonly made by digital recording this reduction process can conveniently be carried out by computer.

The sketchy structural section on the right above illustrates another case where a well's logs will show apparent thickness: where a vertical well penetrates steeply dipping beds. In theory it should be possible to correct the logs for dip, just as in the first case they were corrected for deviation; however, in practice the dip is often not known with sufficient accuracy to allow a useful result. (It will be noted that in the sketch it has been assumed that the folding has not affected the thickness between the markers. Also the section is supposed to be situated in the direction of maximum dip, otherwise the section would not show the true stratigraphic thickness.)

FAULT GAP

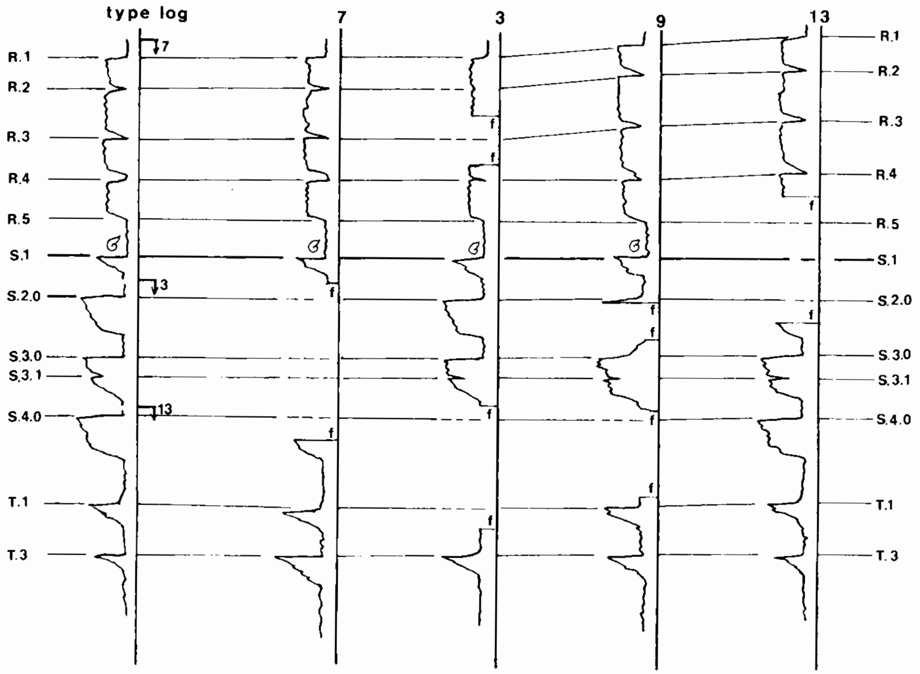


Faults, as will be stressed in the following chapters, are a very important element in the structure of an oilfield. Already in the correlation phase of a study, faults play an important part, often creating difficulties by obscuring the regular order of the layers.

Probably the most common case is sketched in the upper drawings: a normal fault is penetrated by a well, correlation shows that part of the stratigraphic column (marker b with adjacent intervals) is missing, leaving a correlation gap or fault gap. The thickness of the missing section depends on the amount of throw of the fault (see Section C.11).

There exists another case in which faulting can cause a correlation gap: in cases where a deviated well penetrates a reverse fault, going from the low to the high block. As the sketch shows, this is possible only if the well's angle of deviation from the vertical is larger than the complement of the dip of the fault plane (the 'hade'). In practice this is not at all excluded, as reverse faults may well have dips of 60° or more (hade 30° or less) and wells are frequently deviated up to 60°.

FAULT GAPS



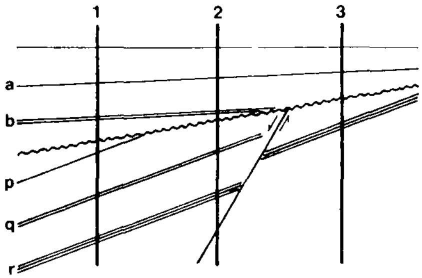
The above correlation chart is intended to show the complicating effects of fault gaps in correlation work.

A simple case is the gap in well 3 where marker R.3 is believed missing. The section between markers R.1 and R.4 is quite similar in the other three wells and there can be little doubt that the gap in well 3 is indeed caused by a normal fault.

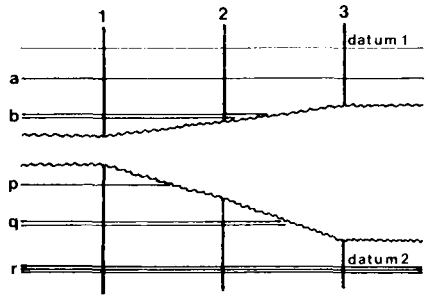
More complex is the situation between markers S.1 and T.1, both well established markers in three wells. Between these two markers wells 3 and 13 show two sand patterns of good similarity. Well 9 shows only one sand and a possible fraction of another; well 7 penetrated only a fraction of one sand. It could be postulated that two sands occur between S.1 and T.1. However, the lower of the two sands in well 3 and the upper in 13 are similarly marked by a thin shale depression in the middle. This suggests the conclusion that these are indeed the same sand and that three sands exist between S.1 and T.1. This is shown in the type log.

This story – fictional but reasonably realistic – illustrates well that correlation is rarely an exact science: the presence of three sands between markers S.1 and T.1 is likely but by no means proved!

UNCONFORMITY GAP



structural section

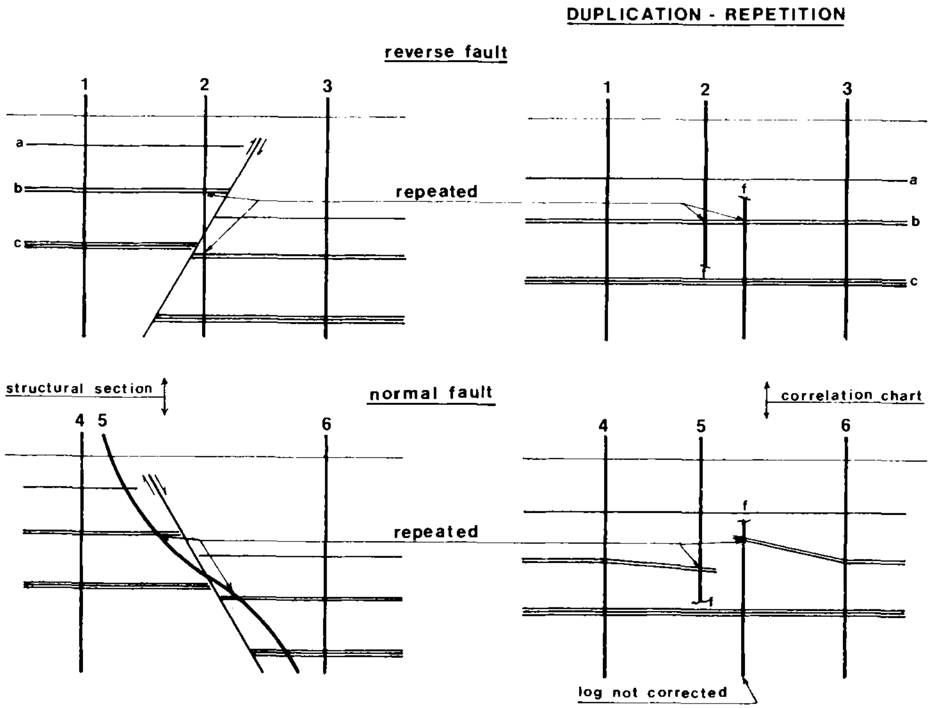


correlation chart

Faults do not constitute the only element in structural geology which can produce correlation gaps, as described in the preceding pages. The diagrams above show that similar gaps can occur as a consequence of the wells penetrating an angular unconformity.

The correlation chart clearly illustrates that the dimension of the correlation gap can vary considerably from well to well, which does not make correlation of beds in the vicinity of an unconformity any easier. There is one more or less constant aspect, however: the correlation gap occurs at more or less the same stratigraphic level in all wells: between markers a and r.

This can be of importance in recognizing correlation gaps caused by unconformity: if the gaps occur at more or less the same stratigraphic level in a number of wells, it is likely that they are caused by an unconformity. Theoretically, such gaps could also be caused by a number of normal faults cutting these wells; but the probability of faults cutting these wells all at more or less the same stratigraphic level is not high. Nevertheless, it is often difficult to decide which of the two possible alternatives is the correct one.

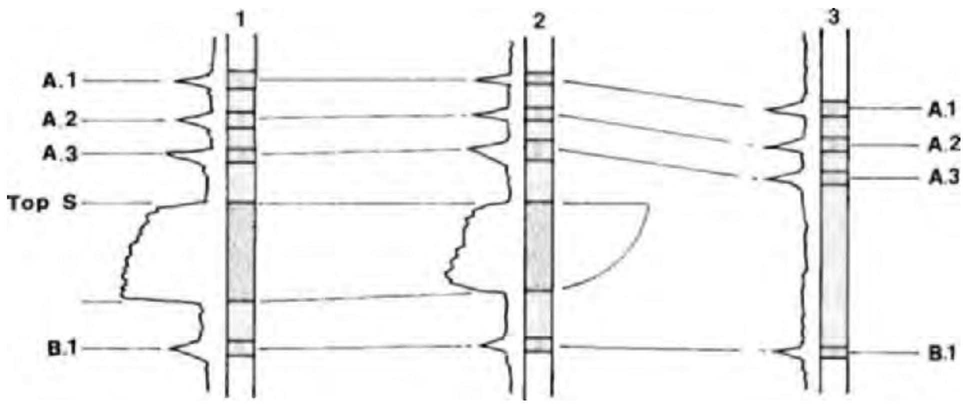


The reverse of the fault gap is the duplication (or repetition): instead of part of the stratigraphic sequence being missing, an interval is duplicated in the well log. The most common cause of this situation is the existence of a reverse fault which is penetrated in a vertical well (upper diagrams). The repeated sections are generally enough alike to be recognized as such, despite the fact that they were a short distance apart before the fault was formed.

In the same way as a reverse fault, in combination with a deviated well, can produce a correlation gap, a 'pseudo-duplication' can result when a deviated well crosses a normal fault from the low block to the high one (lower drawings).

It must be emphasized that in many cases the dip and strike of a fault plane are not known and it will be seen that in the case sketched above the same duplication could have been produced by a reverse fault dipping in the opposite direction. Mutatis mutandis the same of course applies for a reverse fault and a deviated well (p. B.5-2): the same effect would be produced by a normal fault dipping the other way. In such cases fundamentally different interpretations of the same set of data are possible, causing what are probably the most vexing problems in production geology.

DISCONTINUITY



correlation chart

The – highly schematic – sketch above is intended to indicate the complications that may arise when dealing with rapid lateral variations of sedimentary units. There will be little difficulty in the recognition of the markers A.1, A.2 and A.3; B.1 also seems to be well established. But the S-sand is missing in well 3. This could be the result of a fault cutting the well, but the distance between markers A.3 and B.1 in this well is not such that a gap could be present large enough to accommodate the complete S-sand. The more probable solution is to assume that the sand has an abrupt edge – possibly a channel type sand – between wells 2 and 3. This possibility is further supported by the reduction in thickness of the interval A.3-B.1, which may be ascribed to differential compaction effects.

This case may also be used to cast doubt upon the advisibility of using the computer for correlation work (as has been suggested). Comparison of curves, by numerical means, in order to obtain a 'best fit' is of course possible. But in the above case the deflection of the curve for the sand is numerically much more weighty than the small-sized deflections of the small peaks; nevertheless the peaks are geologically more important than the sand. It seems doubtful that the computer could be conveniently programmed to ignore the presence of the sand in the two wells, in comparison to its absence in the third.

B.6 REVIEW

Correlation – in production geological work – is predominantly a matter of comparing the shapes of the curves on logs taken in a number of wells. The immediate objective is to identify intervals in the various wells which have produced logs of sufficient similarity to postulate that the intervals are 'identical' in a geologic or stratigraphic sense.

This implies that the comparison procedure should not be allowed to degenerate into an automatic process, which could as well be entrusted to the computer. On the contrary, the geologist engaged in correlation work should already have in mind a fairly well-developed idea of the general geological conditions prevailing in the formations he is dealing with. For instance, he should take into account whether any faults in the area are likely to be of normal or reverse type; he should be aware of the possible presence of discontinuous channel sands; etc. Only when using the complete pre-information that may be available can he expect to arrive at the most likely correlation.

It is also important to realise that the correlations adopted are, in principle, never more than 'most likely' interpretations. In other words, correlations are not unique solutions and the correlation table is not an immutable document.

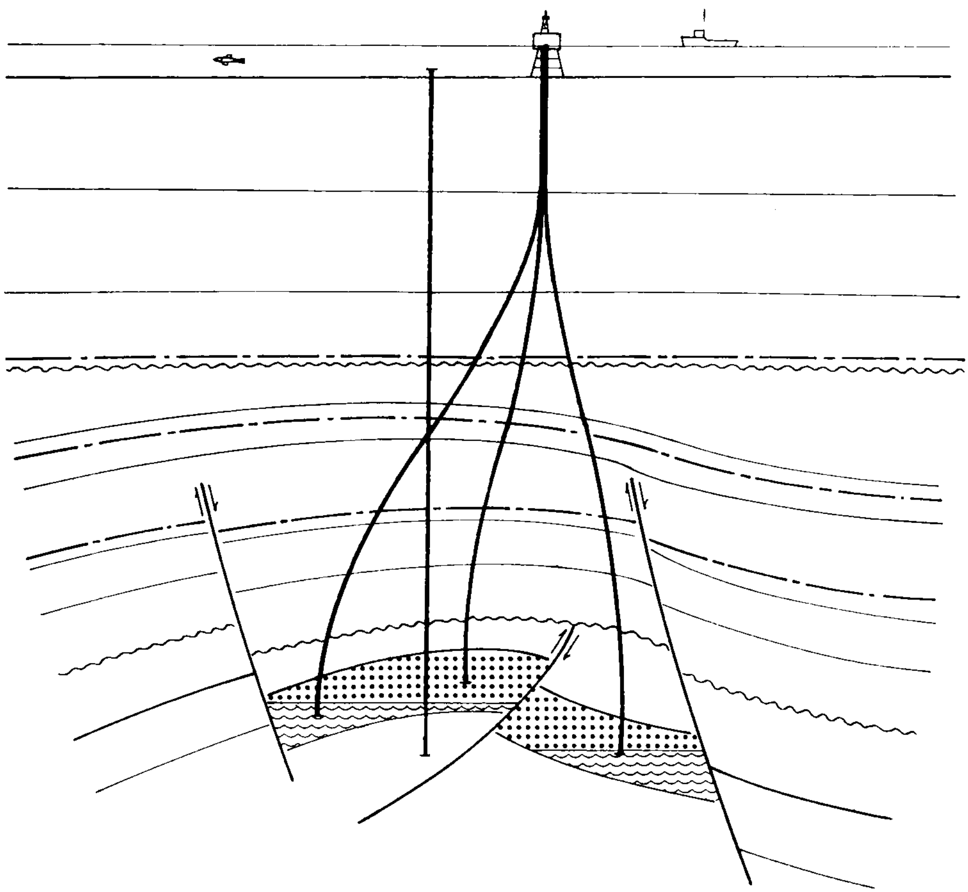
Correlation is not more than a preliminary to the subsequent work in tectonics and sedimentology, for which the correlation provides part of the data. But it is certainly not unusual that during this later work a correlation, as initially adopted, proves to be irreconcilable with other evidence or to lead to structural solutions which are unlikely. The correlation then has to be revised and modified to a 'second best' choice in order to ensure that the geological picture as eventually produced is, overall, 'the most likely'.

Chapter C

TECTONICS (STRUCTURAL GEOLOGY)

C.1 PRINCIPLES

INFORMATION



We may, for convenience, assume that the sedimentary layers with which we deal in production geology, were grosso modo originally deposited as horizontal sheets. Since that time they have been deformed by tectonic processes and they now form intricate three-dimensional complexes of rock.

In oilfields these complexes are in all cases buried in the subsurface, often covered with thousands of feet of relatively undeformed overburden sediments and in many cases by many metres of seawater. Nevertheless, the production geologist is expected to construct the *best possible* picture of the tectonic structure of his field.

For use in this construction the geologist has at his disposal two groups of data:

- data from the wells;
- geophysical information.

The figure above shows the structure of an imaginary but not, it is believed, impossible oilfield and is intended to show symbolically the rather meagre sampling of the geometry of this structure which the geologist has available from the two data sources. Seismic work has provided three, fairly reliable looking reflecting horizons, but it must be noted: none below the lower unconformity, where the serious complications of the structure are situated. One vertical exploration well and three deviated development wells are the only additional sources of information. (Presumably there are other wells outside the plane of the section which will also contribute data.)

Experience shows that the paucity of relevant information has an important practical consequence: in practice the information is never sufficient to impose the adoption of one specific structural interpretation. In other words, there are *no unique solutions* in the work on the tectonic structure of oilfields.

This in turn means that the geologist has to make a choice of several possible interpretations in order to arrive at his 'best possible' reconstruction. In making this selection he is guided by the mental picture which he has to form of what the structure looks like. In other words, he has to form a 'conceptual model' of the structure and work towards that in making his interpretations.

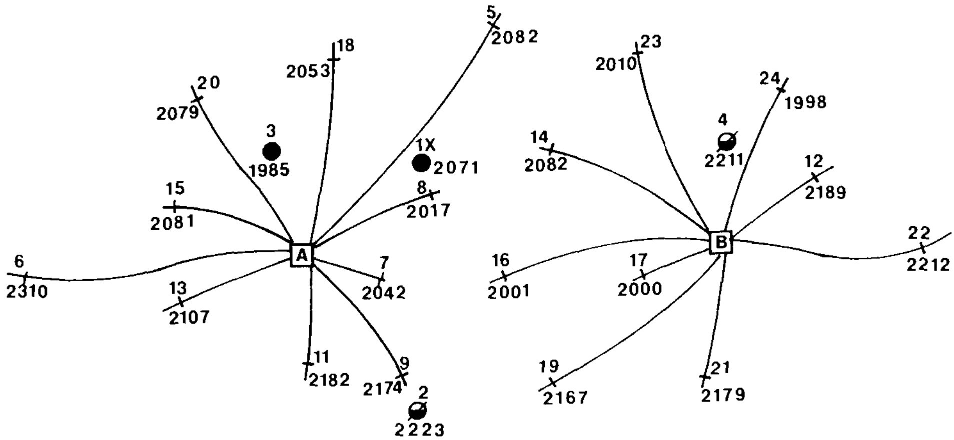
This conceptual model he derives from:

- the available data (ref. Sections C.2, C.3, C.4);
- his knowledge of the regional tectonics of the area in which his field is located, generally obtained from his colleagues in exploration,
- his general knowledge of structural geology and his experience (ref. Sections C.10, C.11).

Having decided on the most likely model of the structure and with due regard for, and proper use of, *all* available data, the geologist constructs his maps, sections and other documents needed to portray the three-dimensional geometry of those layers which are of interest for the development of the oilfield.

C.2 DEPTH DATA

BASE MAP



Structural interpretation is the portrayal – on a suitable scale – of the three-dimensional configuration of a number of planes in the subsurface. The main body of observations on which this reconstruction is to be based is formed by the points at which the wells of the field penetrate the plane(s) in question. Therefore the position of these points in space has to be defined by some form of three-dimensional coordinate system.

In all oilfields the wellhead position of each well is measured and recorded in some convenient coordinate system: geographical coordinates or some other special system for local use. For vertical wells this surface position can also be used to map points at depth in the wells; no well is truly vertical but for wells which are not intentionally deviated, the actual deviation is usually so small as to be negligible for practical purposes.

In purposely deviated wells the position in space of any point along the wellbore can be taken from the deviation survey, expressed in some coordinate system often with the wellhead as origin. These data allow constructing a projection of the well's course onto a horizontal plane, which can be used to put together a 'spider-web map', as shown (in reduced and simplified form) above. Usually such maps will be constructed by computer.

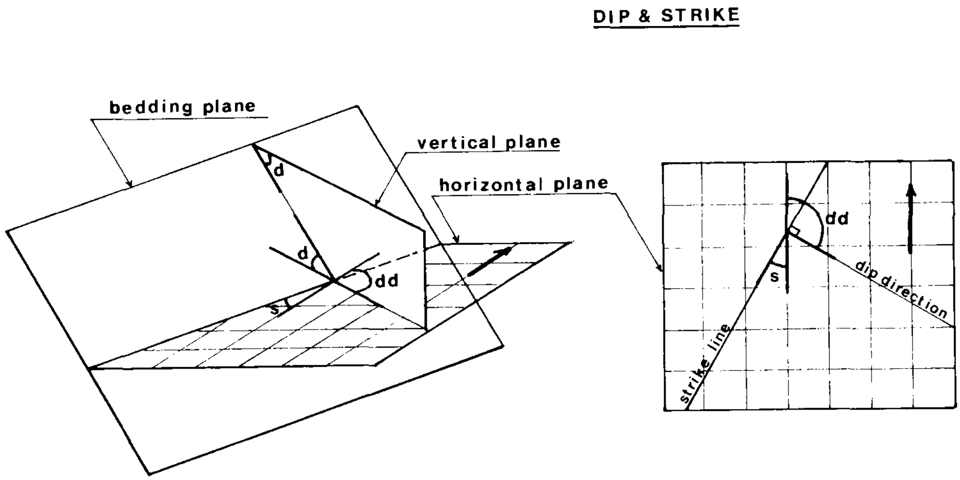
The third coordinate – the depth Z – has to be measured from some common horizontal reference plane; usually this is mean sea level (MSL). Only if the wells are located on relatively high hills it may be more convenient to use a plane above MSL and closer to the earth's surface in order to avoid 'negative depths'. The depths of points in the wells with reference to this datum plane are derived from the correlation tables by subtracting the well's elevation from the along-hole depth (comp. section B.3). For deviated wells the true vertical depth (TVD) of the measuring point is taken from the deviation survey (or directly from the correlation table if this already records the TVD's of the markers), converted to TVD subsea by subtracting the well's elevation and then entered on the spider web map at the correct coordinates for the point, also derived from the deviation survey.

It seems appropriate at this point to discuss the *scales* to which the maps of the production geologist should preferably be drawn. It is in all cases advisable to adopt for working maps the largest possible scale, such that the entire field (or area of interest) can be portrayed on a convenient sheet size and sufficient detail can be shown. For instance, if a sheet size of 0.80 × 0.60 m (standard A-1 size) is used, a field of 5 × 6 km can be portrayed to a scale 1 : 5000. A larger field – of which there are not too many – would require 1 : 10000. Well spacing, i.e. the more or less regular distance between wells in a field, is often between 500 and 1000 m. On maps of the scales mentioned this corresponds to distances between 5 and 20 cm between the points representing the wells; in practice this will be found to be sufficient to accommodate all required detail, without causing an illegible clutter of lines and figures.

Of course, it may be desirable to prepare maps on a smaller scale for display purposes, e.g. on standard A-4 size sheets (210 × 297 mm), which can be copied on the office copier and bound in a standard-size report. Such 'postage stamp maps' however of necessity have to be simplified and inaccurate and should never be used for working purposes.

In the United States the layout of maps is generally determined by the existence in many oilproducing areas of a grid system of 'Sections' of one mile square; 6 × 6 of these Sections make up a 'Township' and several Townships form a 'County'. A convenient system of names and numbers allows defining any point in the terrain within one square mile. Map scales are expressed in inches to the mile; scales corresponding to those mentioned above would be 12 inches to the mile (about 1 : 5000) and 6 inches to the mile (1 : 10000).

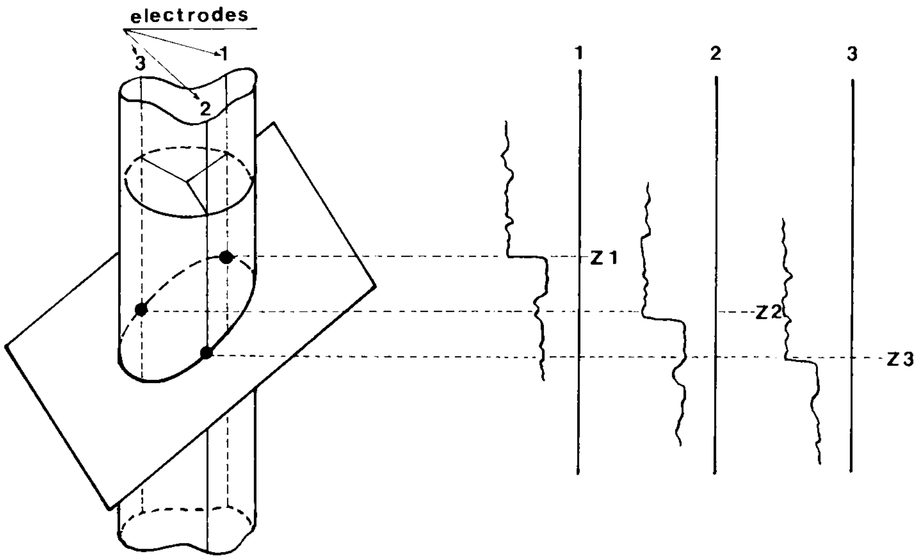
C.3 DIP DATA; THE DIPMETER



It would of course be a great help in the construction of the structural picture if, besides the depth measurements, the attitude in space of the planes of interest could also be known at the observation points. In classical geology this attitude is described by the *strike* of the plane, i.e. the direction of a horizontal line in the plane, measured with respect to the north direction (angle *s* in the diagrams). The *dip* of the plane is measured in a plane at right angles to the strikeline – the vertical plane – as the angle between a horizontal line in this plane and its intersection with the bedding plane (angle *d*). If the strike direction is recorded, the attitude of the plane is not yet fully defined because the direction in which the plane dips has to be added (i.e. to the southwest or the northeast in the case illustrated). This can be avoided if the *dip direction* (= 'dip azimuth') is used instead. This is the angle between the projection of the direction of maximum dip on the horizontal plane and the north direction, angle *dd* in the drawings. This angle is measured as an azimuth, i.e. with values up to 360°.

If one wishes to measure the attitude of a bedding plane at the point where it is penetrated by a well, the most obvious method is to take a sample of the rock. Indeed dips can often be measured on core samples but the reliability is poor because of the small length over which the dip can be measured and the possibility of local disturbances affecting the measured dip. More important, however, is the disadvantage that measurement of the dip direction on a core requires that the north direction is known on the core sample. Techniques for taking 'oriented' cores have been developed but they are laborious, not very accurate and therefore rarely applied.

DIPMETER PRINCIPLE



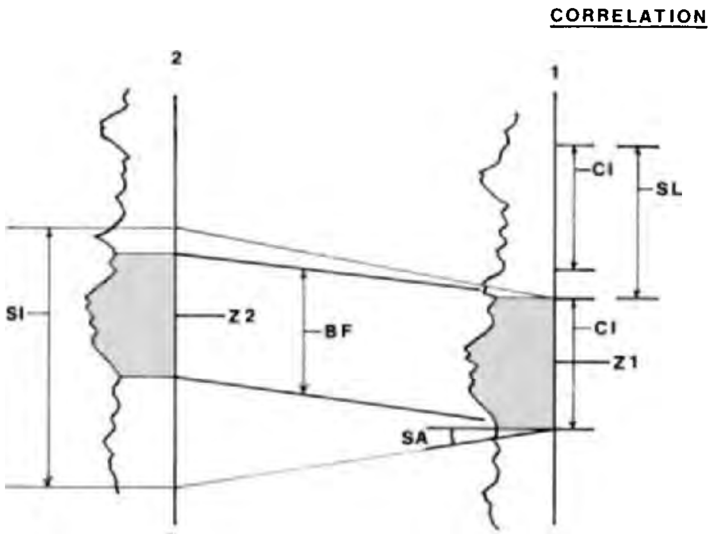
To overcome these difficulties the *dipmeter* was developed many years ago; this is an instrument, run on wireline, capable of effectively measuring dip angle and dip direction of layers penetrated by a well:

The principle is quite simple: three separate logs are produced by running measuring electrodes along three generatrices of the borehole wall, spaced equal angles apart. If an inclined plane, e.g. a bedding plane, intersects the borehole, the three generatrices will meet this plane at different depths. As three points are sufficient to define a flat surface, the attitude of the bedding plane in space can be determined, if:

- the three depths, Z1, Z2 and Z3, of the intersection points are known;
- the orientation of the three measuring electrodes with respect to the north direction is known.

The second requirement is a matter of instrumentation: a compass device is built into the recording instrument which records continuously the angle between north and one of the electrodes.

The first requirement can be met if the bedding plane in question can be recognized on the three logs, by the occurrence of some event such as the sharp 'shoulder' drawn in the figure above. Obviously this is a question of correlation between the three logs. In principle this should not present great difficulties, because the lines along which the logs are recorded are only a few inches apart and there should not be much in the way of lithological differences over such small distances. In practice various disturbing factors – natural and artificial – complicate the process.

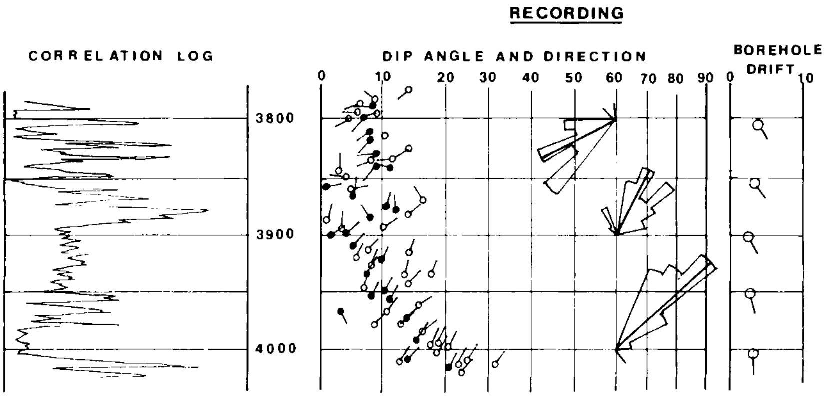


Originally this correlation was carried out by visual inspection. Taking advantage of the digital recording of the logs, the more modern high resolution dipmeter or HDT instrument carries out the correlations by computer.

The above figure shows that in this procedure a specified interval, the 'correlation interval' (CI) on one log is taken into consideration. This interval is then, as it were, moved along the other log, the shapes of the two curves being compared mathematically until the 'best fit' is found. The depths of the two midpoints are then recorded for the further computation of the dip. Naturally, the length of the 'search interval' (SI) on the second log cannot and need not be extended indefinitely; the limits set are expressed in the 'search angle' (SA). The best fit for this correlation interval having been established, a further interval is taken into consideration; the distance between the two successive intervals is known as the 'step length' (SL).

In this procedure three parameters can be selected at will: correlation interval length; search angle and step length. The customer is free to select the values for the three parameters so as to achieve the best results, i.e. the apparently most reliable dip readings. These best values naturally depend on various circumstances of formation character, logging conditions, etc. The selection of the most favourable values is a matter of experimenting, but in practice it is likely that a 'tradition' will develop in a specific area or field. Moreover, later re-processing with different parameters is always possible.

A further innovation introduced with the HDT instrument is that four logs are recorded, instead of three. This has the advantage that different combinations of three logs can be used for correlation. The mathematical procedure allows comparison of the quality of the various combinations computed and the one with the best quality can be selected for recording.



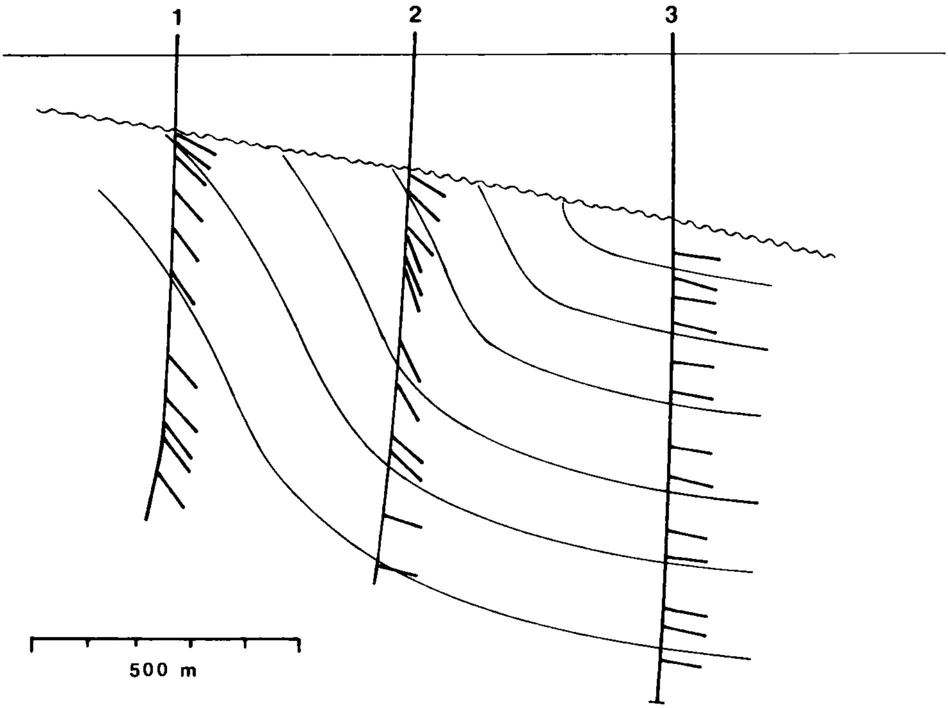
The computations result in a set of three-dimensional vectors, each representing dip angle and direction at a measuring station. These are as yet only numerical values and somehow must be made legible for the user; this can best be done graphically and different systems have been developed. The most convenient and most common is the arrow plot (also known as tadpole plot), shown above. The dip angle is shown by a circle on a scale of degrees up to 90°; the quality of the reading is expressed by closed (= good) or open circles. The tail of the tadpole points in the dip direction (north = upwards).

In this system the single reading can be quite clearly seen. But it is also of importance to visualize the variations with depth of dip angle and dip direction. In the figure the variations of dip angle can be appreciated quite well. The variations in dip direction are less clear; to improve this, the rose diagrams have been added in which the dip directions are summarized, together with a statistical average value for the interval.

The example above shows a clear change of both dip angle and direction at about 3850', indicating that the well crossed an important structural element (fault, unconformity?). Below this depth the dip direction stays fairly constant to the northeast but the dip angle increases gradually from about 5° to about 20°. It would be more difficult to appreciate the attitude of the beds if the dip direction also had changed gradually below 3850. This is to illustrate that, despite the efforts made to design a good system of graphical representation, it is still very difficult to evaluate covariance of dip angle and dip direction.

On the left side of the document a log curve facilitates definition of the stratigraphic unit in which the readings were taken. The right-hand column shows the deviation of the borehole from the vertical, in magnitude and direction; note that the dip readings are corrected for this deviation. The example also shows that the attitude of the hole also changes at about 3850, a not uncommon phenomenon because boreholes tend to orient themselves at right angles to the bedding planes.

STRUCTURAL DIP



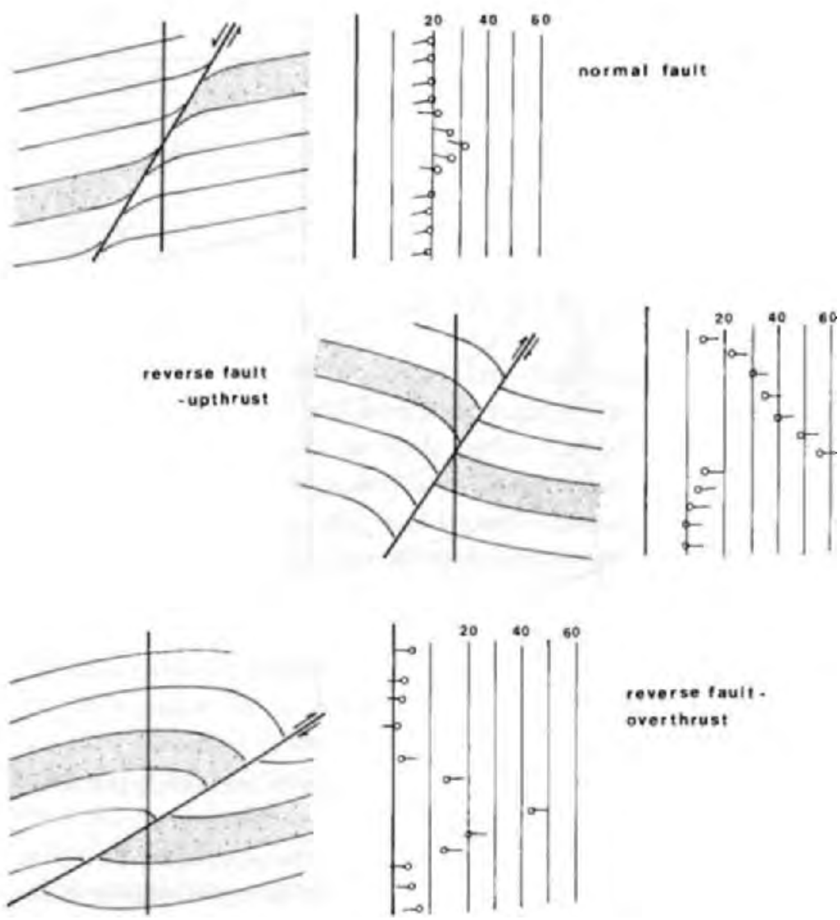
The dipmeter was originally developed for the purpose of measuring the *structural dip.*

In the context of work in structural geology in oilfields, the expression 'measuring the structural dip' means that the measured values should be representative of the attitude of the layers over a fairly extensive area around the borehole. In the following paragraphs dip measurements will be discussed which describe detailed dip configurations restricted to the immediate vicinity of the well.

For the reconstruction of the tectonic structure between the wells, which in an oilfield are generally in the order of several hundreds of metres distant from each other, it is desirable to know dip values that allow effective extrapolation and interpolation of the structural data between the wells.

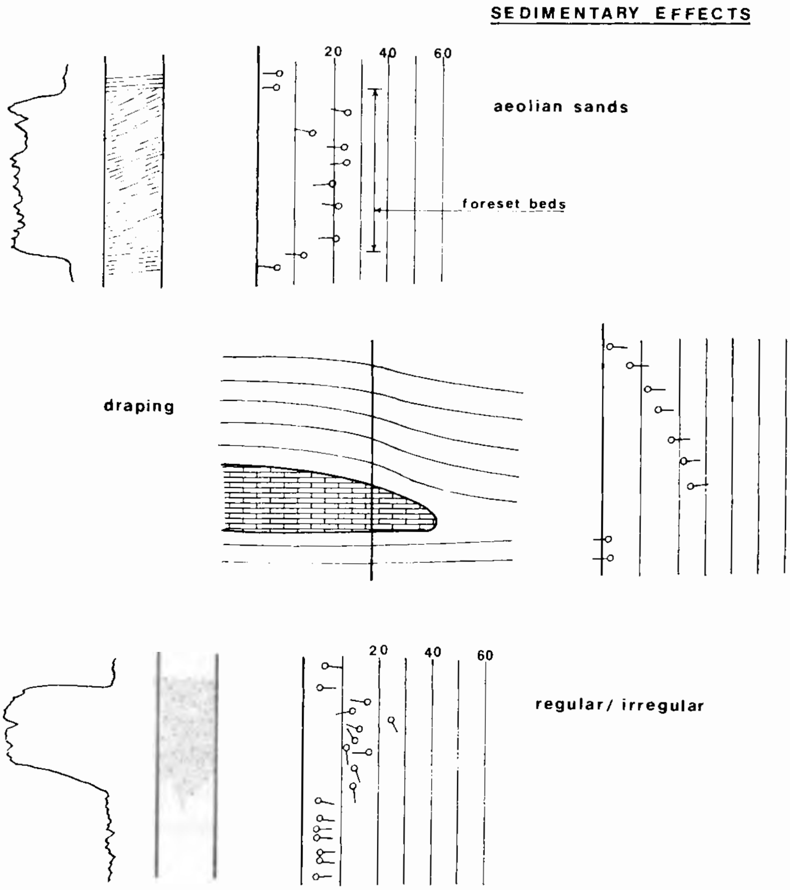
In the example above the dip series in each well show minor irregularities, probably caused by small sedimentary or deformation effects. But considering the overall trends of the dips, a well-defined reconstruction of the flexured structure of the beds proved possible; later drilling in the vicinity fully confirmed this reconstruction.

FAULTS



The three figures show the patterns of dipreadings associated with three types of faults. The drag zone of the normal fault is reflected in an increasing-decreasing pattern. The dip direction of the fault is assumed to be not exactly like that of the beds, resulting in a gradual change in direction measurements as well. The pattern caused by the upthrust reverse fault is similar. In this case the dip direction of fault and beds was assumed to be the same, which is not unlikely as both were probably caused by the same deformation movement. A more complex situation results where, as in the overthrust case, the structural dip is opposite to that in the immediate vicinity of the fault.

It will be clear that the three situations sketched are quite simple and that in reality the dip patterns are likely to be less well defined and consequently the interpretation of the readings more obscure.



Not all measurable dips are caused by tectonic deformation: in many cases the beds are inclined as a result of depositional effects.

The upper figure shows the dip pattern associated with dune sands preserved in the sedimentary record; such deposits are characterized by very marked cross-bedding in the units of foreset beds. The dips in these foresets tend to be close to the maximum angle of deposition of dry sand in air (ca. 30°) and the dip directions vary over small angles only, representing the prevailing wind direction at the time of deposition. The foreset units are often separated by more argillaceous intervals showing a smaller dip, probably representing the structural dip.

The second figure illustrates another – not quite so small-scale – effect: sediments draped over the abrupt edge of a resistant sediment body. This latter can be, as suggested here, a carbonate reef-like body. Similar effects result over the edges of sand bodies, such as channel fills or barrier bars.

In Section B.4 it was mentioned that for purposes of structural work it is best to concentrate on deposits of low-energy environments, say, shales or sandy shales, because these were probably deposited as horizontal sheets originally. A similar preference applies in dipmeter interpretation for purposes of work in tectonics. Low-energy deposits – see the third figure – have two advantages: their deposition was regular over largish areas and the dip stays fairly constant over considerable thicknesses, which in most cases produces clear dipmeter readings. In higher-energy deposits, particularly in sands, the bedding is either insignificant and thus does not provide dipmeter readings at all, or the bedding is current-produced and thus not horizontal originally and not suitable for measuring the structural dip.

The examples shown on the preceding pages illustrate that, as could be expected, similar geological situations tend to produce similar patterns in the dipmeter survey. In practice the geologist uses this relationship: from the occurrence of a specific pattern he concludes that a specific geological situation exists. For instance, the up-and-down pattern shown in the first figure on p. 44 would be interpreted as indicative of a normal fault.

This thought process should not be exaggerated. Formal systems have been proposed for the recognition of such patterns and their geological interpretation. Whereas such a system may be useful in favourable circumstances, it would seem to carry the same drawbacks as other 'cookbook recipes' in geological work: the risk that rigid application of the system may lead to misinterpretations of unclear patterns or to the postulation of structural elements in environments where they do not belong.

In the author's view, the only proper use of the dipmeter is a process of intelligent interpretation, in which the geologist takes into account all geological knowledge available. For instance: the searching for structural dips preferably in low-energy deposits; recognizing draping patterns in a formation where discontinous rock bodies are to be expected; not interpreting reverse faults patterns in an area of extensional tectonics.

The process of dipmeter interpretation should be similar to that of dip observation in a large outcrop. In order to establish the dominant structural dip, the field-geologist will post himself at some distance from the outcrop to get an overall view; he will make mental abstraction of local irregularities; finally he will adopt what appears to him to be the valid overall structural dip. He may then approach more closely and examine the more detailed effects to define cross-bedding, fault effects, etc.

In the same way the geologist interpreting a dipmeter survey should start with the examination of the entire survey over the interval of interest, in a global manner.

This will allow him to recognize and define sections over which the dip angle and dip direction are regular enough to indicate the probability of a reliable structural dip. Having noted these, he can then proceed to the analysis of various irregularities, attempting to explain these in terms of local structural or sedimentary effects, such as faults and current bedding.

It is frequently asked: is the dipmeter reliable? There is a quite simple answer to this question: if the dipmeter did not generally produce useful results, the oil companies would long since have stopped expending large sums of money for running dipmeter surveys. Experience suggests: the dipmeter is right, unless proved wrong.

C.4 SEISMIC INFORMATION

> 'The use of seismic methods in oilfield development is increasing. Until recently geophysicists have not generally been part of development organisations'.
>
> R.E. Sheriff, Geotimes, Febr. 1980.

Not so very long ago the resolving power of the seismic techniques was still so poor that seismic information was rarely of any use on the detailed scale of production geological work in the oilfield. This has changed thoroughly in recent decades and the use of seismic methods specifically for this kind of work is indeed, as the above quotation states, increasing rapidly.

It is obviously not within the objectives of this book to go into a discussion of seismic techniques. But a few commentary remarks on the practical use of seismic information may be justified.

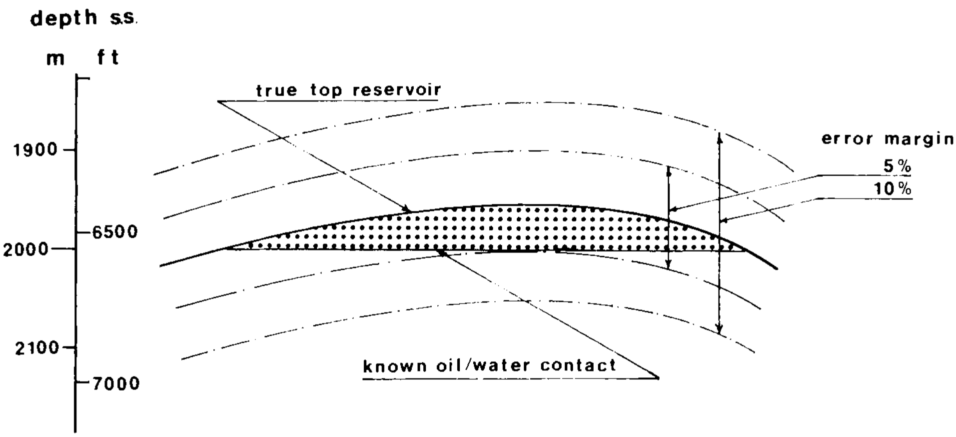
For the purpose of structural interpretation work in the oilfield, two categories of information can be derived from seismic surveys:

- position – i.e. depth and dip – of specific layers:
- occurrence of faults.

Let us assume for the purpose of this discussion that the seismologist has carried out the entire interpretation of the survey results. He has analyzed the available seismic sections and identified the true reflectors, disregarding spurious elements, such as multiples and diffractions. He has noticed and recorded fault indications. He has then transferred these observations to a map, possibly by computer, and finally produced his *best possible* picture of the structure of one or more surfaces in the form of seismic contour maps. The production geologist can then use these maps as a part of the basis for his own interpretations. It is important to remember, however, the emphasis on 'best possible': seismic maps are also human interpretations of incomplete data and no seismologist is likely to lay claim to omniscience and infallibility. The seismic maps, therefore, need not be taken as incontrovertible evidence: the production geologist is – to some extent – free to deviate from the picture shown, if this should be in conflict with the evidence from the wells or with his conceptual model of the structure.

Apart from possible interpretational errors, there may appear, in the seismic image of the structure, inaccuracies of importance for the detailed geological work. For one thing, the resolving power of the seismic process is essentially limited by the width of the individual loop on the seismic record, because within the loop generally no further details can be distinguished. It is worth remembering that loop width is in the order of several tens of feet and that therefore this is the best accuracy that can in practice be expected.

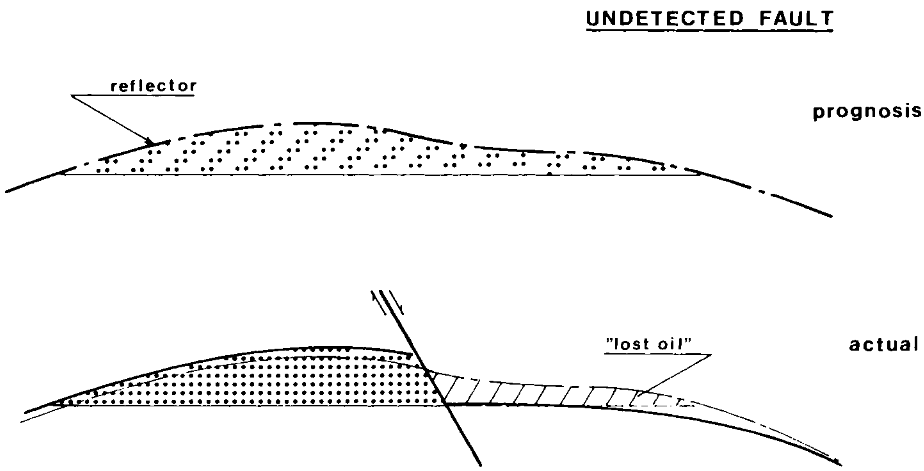
UNCERTAINTY



Another source of possible inaccuracies lies in the conversion of the measured travel time of the seismic waves to reflector depth. The velocity distribution, used in this conversion, is perforce an approximation of reality, which is determined by the lithological composition of the overburden through which the waves have travelled. Inhomogeneities in this lithological composition, caused by lateral variations in the nature of rock units and by thickness variations of these units, can lead to important inaccuracies in both depth and dip of the reconstructed reflectors.

Altogether these, and possibly other, sources of inaccuracy may lead to an error in the depth computations that may go up to, say, 10 percent of the actual depth of the reflector. This may be relatively unimportant in the exploration phase, where only the relative position of 'highs' and 'lows' is of prime importance in the search for promising structures.

The figure above tries to show that such possible inaccuracies can be quite serious in production geology. Sketched is a situation where the top of a reservoir zone is no more than 50 m (ca. 150 ft) above the known depth of the oil/water contact, a good-sized oil-column-height in many oilfields. If the seismic interpretation contains a total error margin of 5% of the depth of 2000 m, the top of the reservoir could appear on the seismic map at a depth 50 m (= 2.5% of 2000 m) below the actual position. In consequence, the formation would be supposed to be below the oil-zone and thus not worth drilling for. Conversely, the seismic map might give too optimistic a picture and suggest that some 100 m of oil-bearing formation is present. Similar possibilities of course exist a fortiori if a margin of error of 10% is assumed.



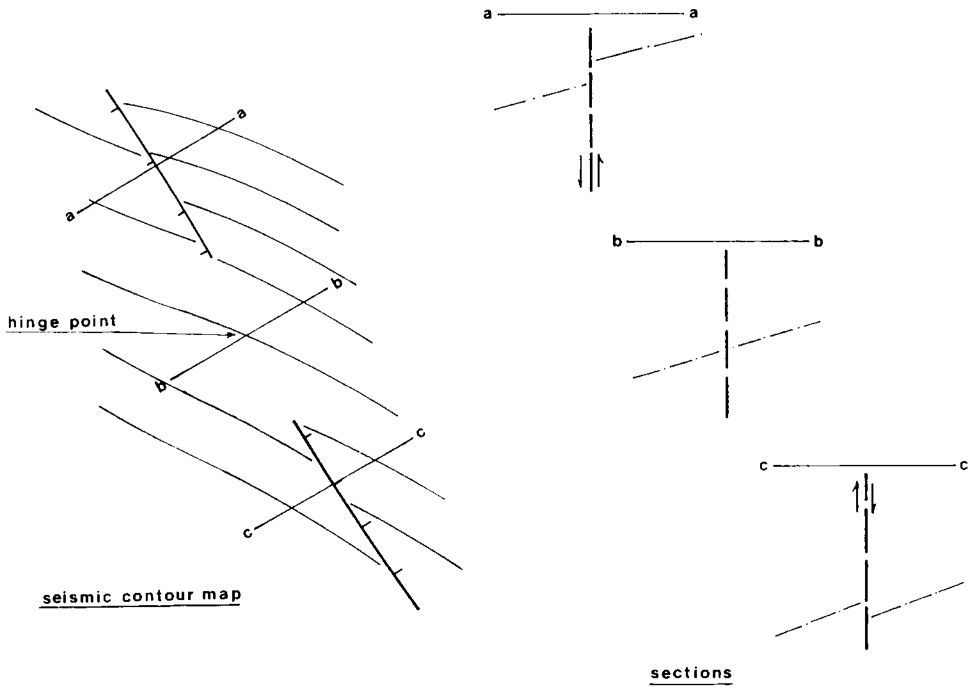
The other category of information – very important in production geology – which the seismic techniques can contribute, regards the presence of *faults*, and the attitude of fault planes in space. For the production geologist, who otherwise could hope at best for a few observations of fault crossings in wells, this information is invaluable in fleshing out his picture of the fault pattern.

This having been stated emphatically, to avoid the odium of ingratitude, it is perhaps permitted to point out some weaknesses in the information, as a warning for possible pitfalls.

On seismic sections faults can, almost without exception, only be recognized by offsets in reflectors. This means, in the first place, that reflectors of sufficient clarity must be available for such offsets to be visible. Moreover, it may be correct to suggest that faults are generally accompanied by zones of disturbed rock, from which no clear reflections can be expected; therefore faults rarely show up as sharp breaks in a reflector, but as gaps of some width interrupting its continuity. This in practice often prevents accurate definition of the fault's position.

Moreover, also in practice, the offset of the reflector has to be larger than loop-width to be readily recognizable. Consequently, faults with a throw of less than loop-width, i.e. a few tens of feet, are unlikely to be observed. Such faults are not important in regional, exploration work, but can be quite harmful in oilfield work, as is illustrated in the diagram. In the context of oilfield work, 'harmful' usually means that the estimated volume of oil present in the reservoir is reduced by the new evidence. Such cases of unrecognized faults of course mostly concern faults of a few tens of feet of throw only, but cases where the thickness of the oilzone is of the same order are by no means rare either. Moreover, even larger faults have also often gone undetected!

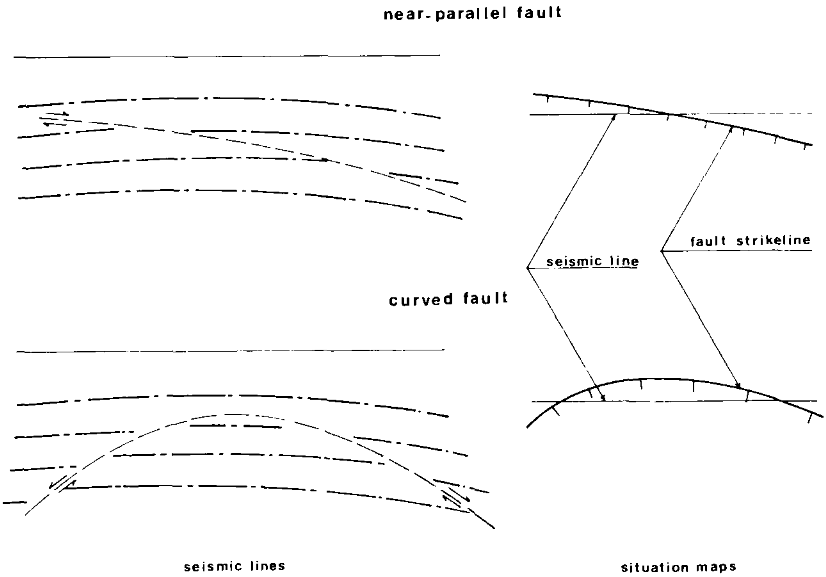
HINGE FAULT



Because faults are recognizable on seismic sections only by the offsets in reflectors, hinge faults may go undetected on lines crossing the fault near the hinge point.

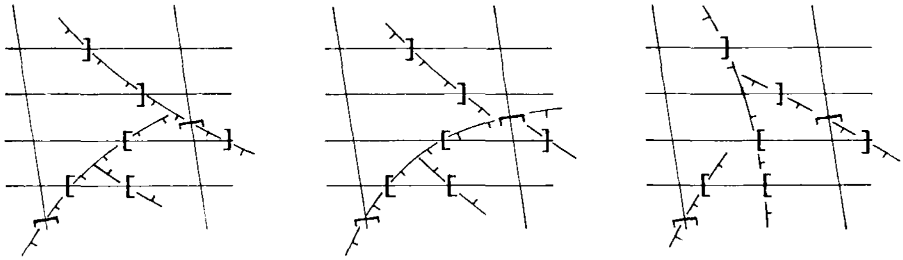
Section b – b above schematically illustrates this condition. As the parts of the reflector on either side of the fault are accurately in line, it is unlikely that the fault will be recognized. As a result of this possible oversight, it is not uncommon to find on seismic maps fault stretches, in line with each other, but throwing in opposite directions and separated by a gap, as shown on the map above. In areas where the occurrence of such hinge faults (areas characterized by transcurrent movements) is likely, it may be assumed that the fault is, in fact, continuous across the gap.

INCONSPICUOUS FAULTS



If the strike of a fault makes only a small angle with a seismic line, the trace of the fault on the seismic section plane will be nearly horizontal (see also Section C.6). The gaps in the reflectors on the section, corresponding to the intersections with the fault trace, will be wide and they will be a long distance apart laterally on the different reflectors. The recognition of the fault will be quite difficult in those cases and the fault is likely to be missed.

Similar difficulties arise where a seismic line intersects a fault which is curved in plan view. Such faults may not be too common – except perhaps in a certain tectonic style (ref. Section C.8) – but the possibility of such faults being present but missed must be borne in mind.



After the interpretation of the seismic sections, the next step is the construction of a contour map on a recognizable reflector (or on each of several reflectors). The basis for the map is a pattern of seismic lines, usually a grid of two or three different directions of lines. To this grid are then transferred the depth determinations of the reflector on each of the lines. Similarly the fault indications found on the sections are marked on the grid map, as shown above; as the angle between the seismic line and the fault strike is rarely known at this stage, the fault symbols will generally be drawn normal to the line direction.

The next problem then is to decide which of the fault crossings belong to the same fault. The above figures are intended to symbolize that the data in many cases allow considerable freedom to choose different patterns. There may, of course, be additional information which should be taken into account in making the choice of pattern; well data may help to impose a certain preference. But, also, this information is often derived from knowledge of local tectonic style; in other words, a conceptual model of the most likely pattern will play its part in these interpretations (comp. Section C.1).

It may be useful to mention that there is often a natural tendency on the part of seismic interpreters to select fault patterns such that the dominant trend of the faults is at right angles to the grid of seismic lines. Such patterns may be in contradiction to the well data, or, again, to the conceptual model of the most likely fault pattern and a revision of the seismic interpretation may then be requested.

At the risk of appearing ungrateful for the contribution that seismic methods can make to the geological analysis and description of oilfields, the author has ventured in the preceding pages to point out a number of possible sources of inaccuracies, errors or uncertainties of interpretation in seismic work. It will be clear that in many cases these weaknesses will be reduced by improvements in acquisition and processing of the seismic data, such as have been achieved in recent years, especially since the introduction of digital recording and the use of computerized methods.

Technical development is extremely rapid and the application of seismic methods in production geology is growing correspondingly, to the great benefit of the production geologist. However, the degree of technical sophistication is so impressive that there is a growing tendency to an excessive dependence on the seismic information. Geologists are inclined to accept the seismic maps as undisputed facts and, in consequence, to neglect the analysis and evaluation of the other geological information that is available. In fact, the manager of a petroleum engineering department of a major oil company recently complained to the author that his men were forgetting the uses of 'classical' production geology, to the detriment of the success ratio of the development drilling.

The best way to overcome such a tendency is to have the geological picture of a field worked out in close cooperation between well-trained production geologists and seismologists. The resulting geological picture, portrayed in suitable maps and sections, should be seen as the joint effort made under joint responsibility of the two specialists. Experience shows that this can best be achieved if the production geologists and seismologists are members of the same organizational unit; fortunately, the statement quoted at the head of this section (p. 48) indicates that this is indeed the case in an increasing number of companies.

C.5 TECHNIQUES

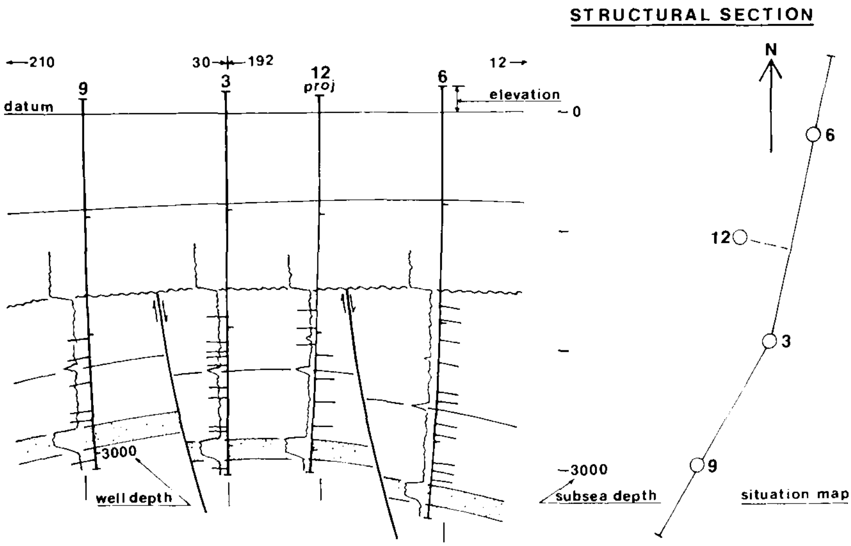
The discussion in the preceding sections was concerned with the information which the production geologist has at his disposal for the working out of the tectonic structure of his field(s). Using this information he has to develop his 'most likely' picture of the structure. For this purpose he uses mainly two categories of diagrams: sections and maps.

In principle these diagrams are the same as the similar documents commonly used in academic and exploration geology. In work in these disciplines, the maps and sections are in the first place means of recording the observations made in the course of the investigation, e.g. field work. Secondly, they are illustrations of the geological concept – in a wide sense – which was developed from these data: e.g. the structure of a mountain chain, the palaeogeography of a formation. Such documents are to be used mainly for the drawing of *qualitative* conclusions; rarely are they used for quantitative purposes.

By contrast, the maps and sections which the production geologist produces, are to be used for very definite purposes of an engineering nature: selecting well targets; predicting the depth of specific layers, especially reservoirs; estimating reserves; constructing numerical reservoir models. These applications are to be discussed in more detail in Chapters G to J and it is hoped to make clear then the demands which these applications impose on the accuracy of the data taken from the maps and sections. In other words, the maps and sections of the production geologist are more like the construction drawings of the engineer and they have to be correspondingly accurate and reliable.

These working papers of the production geologist are to be discussed in the following sections. Section C.6 will describe the characteristics and the preparation of the structural sections. Section C.7 deals with the techniques of constructing structural contour maps; C.8 describes thickness maps and some other types of diagrams are briefly touched upon in Section C.9.

C.6 STRUCTURAL SECTIONS



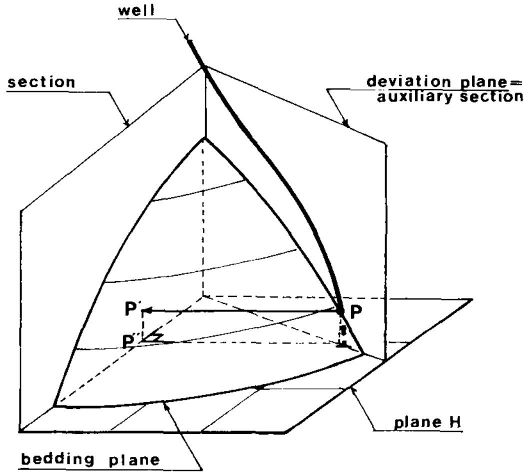
In structural work in a field of any tectonic complexity, sections are the first step in the procedure. They serve in the first place as analytical tools with which the structure is 'dissected' on a number of vertical planes, arranged so as to include as much as possible of the available well information and to stand the best chance of revealing the complexities of the structure. Once the structural picture for each section has been completed, the three-dimensional picture is constructued by 'connecting' the sections with a set of contour maps.

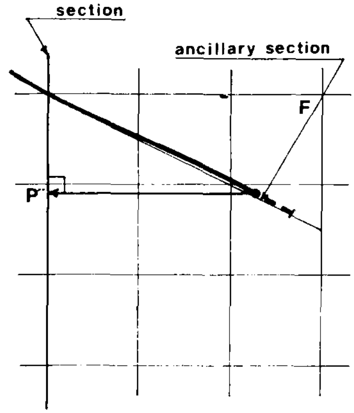
A structural section through an oilfield shows images of wells, or parts of wells, represented by lines alongside of which the data of interest are shown by appropriate symbols. The first requirement is to ensure that these lines are shown on the paper in accordance with the true spatial relationship of the wells; if this were not achieved, the resulting structural interpretation would be deformed with respect to reality.

Thus the well images should be spaced on the section accurately in accordance with their position in the field, i.e. the distances between the well centre-lines must be strictly to scale. (It will be remembered that this requirement does not necessarily hold for the Correlation Chart, which is similar in appearance to the structural section.)

Next it must be ensured that the depths involved are properly represented. This means that a horizontal datum, or line of reference, must be chosen; this can be Mean Sea Level or some deeper level if the structure of the upper formations is of no interest – as is often the case. Again, in the interest of making the structural interpretation correspond as accurately as possible to reality, the vertical scale must be equal to the horizontal scale: structural sections must *not* be 'exaggerated'.

DEVIATED WELL





projection on plane H

Because wells are rarely strictly vertical, and in fact often purposely deviated over considerable angles, the true course of the well must be shown on the sections as accurately as possible. This is achieved by projecting the well course onto the section plane. For nearly vertical wells this is relatively simple, as shown on p. 56.

For severely deviated wells the procedure is more complex. The drawing above is intended to make clear that such wells can be properly shown only in sections the plane of which runs close to the well course; if not, data would be projected into the section which reflects actual conditions a long way from the section plane.

The deviated well penetrates the bedding plane at point P. This point is, in principle, projected onto the section plane along a line normal to this plane, i.e. to point P'. But the actual intersection of the section plane with the bedding plane, which of course is to be shown in the section, does not pass through this point P' at all and this point thus provides only misleading information.

The confusing effect of projecting the deviated well by the conventional method can be avoided by constructing a special, auxiliary section in a plane as close as possible to the course of the well. This will allow using the information from the well in the most correct manner, at the line of intersection of the auxiliary section and the main section.

An important point to settle is the scale to which the sections should be drawn. Similar considerations as were advanced when the scale of maps was discussed in Section C.2, lead in practice to scales of 1 : 2500 or 1 : 5000 (approximately 1″ = 250′ or 1″ = 500′). On a standard A-1 sheet (0.80 × 0.60 m) with a frequently occurring well spacing of 600 m (approximately 80 ac. spacing), five wells can be depicted over a depth interval of 2000 m (6000 ft). In most cases this is quite sufficient: enough detail can be shown without producing an illegible cluster of lines and symbols and the paper size can conveniently be handled. A smaller scale, say 1 : 10 000 or smaller, is usually too cramped for proper working, but may of course be used for illustrative purposes, such as the sketch section shown on p. 56.

The same figure also shows a number of more or less 'administrative' data which have to be included: the wells are plotted from the adopted datum with the help of the well elevations (D.F. or K.B.) derived from the correlation tables; the well depths are shown at convenient intervals, say every 1000 or 500 m or 1000 ft, along the centre lines representing the wells; subsea depths can be shown as small marks with appropriate depth figures along the side of the section, or the corresponding depth lines can be drawn across the section (which is convenient for measuring depths); the direction of the section should be shown, preferably as azimuth (rather than the 'N.n°.E system').

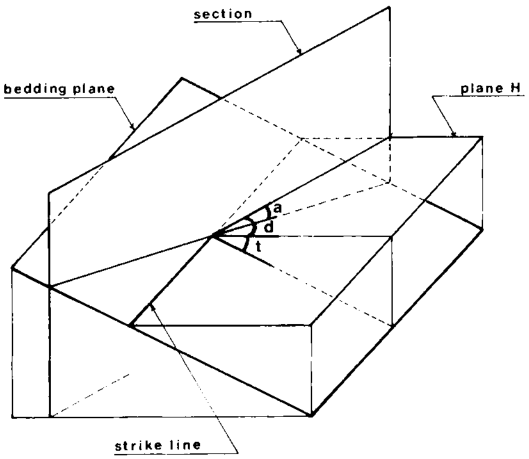
When the topographic and administrative data have thus been properly entered, the geological information has to be displayed.

First comes the stratigraphic or depth information (ref.Section C.2): the along-hole depths of markers, unconformities, faults, etc, are read from the correlation table and shown by some symbol on the centre line; well depths are measured off from the depth marks already entered. Obviously, the markers have to be identified by the marker name or number, in order to allow connecting the same markers in the various wells. At this stage it has probably not yet been established which of the fault intersections (fault gaps or duplications) are to be ascribed to the same fault and accordingly a fault nomenclature system will be introduced at a later stage.

Because all pertinent information that can be taken from the well-logs should have been collected during the correlation procedure and comprehensively recorded in the correlation table, it should be unnecessary at this stage to copy log curves alongside the well centre lines on structural sections; in fact, doing so would probably introduce unnecessary lines on the section and make the picture less legible. However, it may be useful to construct illustrative sections for communication purposes. These would probably be on a smaller scale (1 : 10 000 or 1 : 25 000) than the working sections. It may be helpful to show a log curve on such sections for intervals of particular interest; this may, for instance, help reservoir engineers in visualizing the spatial characteristics of a reservoir.

The method of introducing seismic information on a section depends on the working conditions. If the production geologist has been presented with a seismic map, or a set of maps, as a finished product, he will trace the section line on the map(s) and plot on the section the depths read off from the contours at the points where they cross the section line. A line drawn through the plotted points then represents the seismic reflector on the section. As it is – usually – a reflector, it does not necessarily correspond to any of the levels which the geologist has chosen for mapping. The 'seismic line' on the section can of course be used as guidance for the construction of the other lines on the section, which represent bedding planes or markers. Faults indicated by the seismic will naturally be shown on the section as well.

If the structure of the field is being worked out in cooperation between the production geologist and the seismologist, the procedure will naturally be different. For one thing, it will then be advisable to select the sections, if possible, along some of the seismic lines. As a first step the well data can then be transferred to these seismic sections and be of assistance in the interpretation. In this operation account has naturally to be taken of whether the seismic section is a time section or a depth section and the correct time/depth conversion has to be used. The geological interpretation of such combined seismic and field sections is obviously best carried out as a joint effort by production geologist and seismologist.



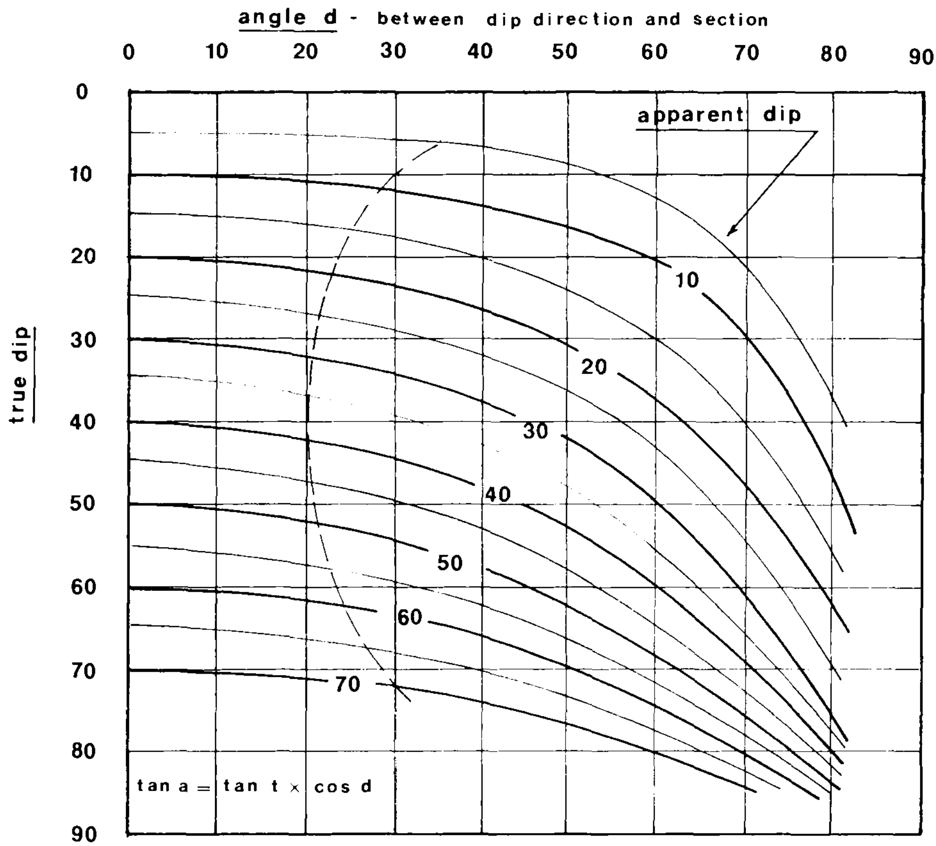
APPARENT DIP

The third category of information, the dip data mostly derived from the dipmeter, is of course also used in section construction.

In principle it might be of interest to use all readings reported in the dipmeter survey. In practice the large numbers of readings provided by the modern surveys make the transfer of all these readings to the section prohibitively labour-intensive. The best alternative is to use averages. For the dip angle values it is probably best to select from the survey intervals over which the dip remains fairly constant and to determine a suitable average visually; this is usually not too difficult from the tad-pole plot. The average for the dip direction is more difficult and can best be taken from the rose diagrams provided in the survey report. Of course, if the dipmeter results are available in computerized form a special program for averaging over selected intervals can be applied. As a result a representative dip value can be plotted on the sections at convenient intervals along the well centre line.

Before this can be done accurately, however, the dip values may have to be corrected. This is required if the dip direction does not coincide with the direction of the section. The maximum or *true dip* of a bedding plane is measured in a plane normal to a horizontal line, or strikeline, in the bedding plane (comp.Section C.3). In any other plane, making a smaller angle than 90° with the strikeline, the dip is always smaller than the true dip and known as the *apparent dip*. In the drawing, the true dip is shown as angle t and the dip in the section plane as angle a, which is smaller than angle t. If the true dip is known, from dipmeter, it has to be corrected to the apparent dip to be shown on the section. The correction depends on the angle between the dip direction and the section plane direction; the nomogram on the next page provides the numerical values.

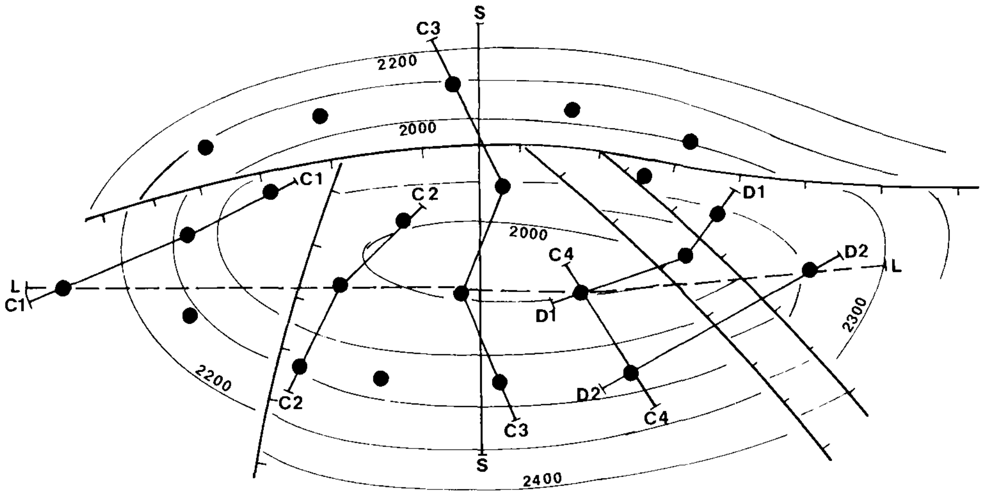
DIP CORRECTION



The reading of the corrected values from the nomogram is straightforward: e.g. if the true dip is 30° and the angle between dip direction and section is 50°, the apparent dip in the section plane is approximately 19°.

It is of interest to note that in the area to the left of the dashed line in the nomogram the corrections are no larger than two or three degrees. In practically all cases this is probably within the range of uncertainty of the dipmeter readings: in these cases it becomes unnecessary to carry out the corrections. The nomogram shows that this consideration applies whenever the angle between dip direction and section is less than 20°; it is convenient to keep this figure in mind.

SUITABLE SECTION LINES



Structural sections were described as analytical tools with which to dissect the structure. To fulfill this function they have to be in optimum position on the structure; two requirements have to be met:

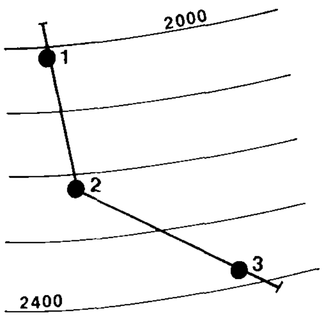
- the geological structure has to be portrayed as clearly as possible;
- the maximum of factual information should be included in the section.

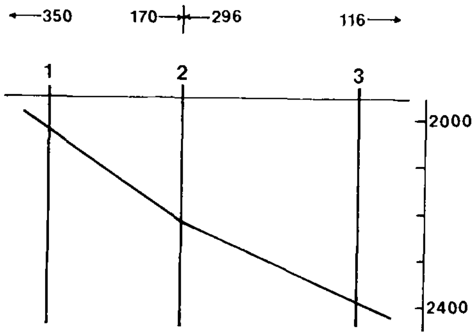
To meet the first requirement, sections should be as much as possible in the direction of true dip, because then the influence of inaccuracies in the dip measurements is least and the thicknesses to be used are true thicknesses. Therefore sections are best selected roughly at right angles to the overall trend of the structure; such cross sections or dip sections, are marked 'C' in the figure.

Longitudinal or strike sections may be useful for illustrative purposes or as a connecting link between a series of cross sections to check whether this series is geometrically consistent within itself (marked 'L').

It may be objected that the structural work is done to define the shape of the structure and that therefore the direction of the sections cannot be chosen properly beforehand. However, in most cases the overall shape of the structure is known from seismic. Moreover, many structural studies are carried out as review studies when the field is already largely drilled-up (comp. Chapter J).

ANGLED SECTION





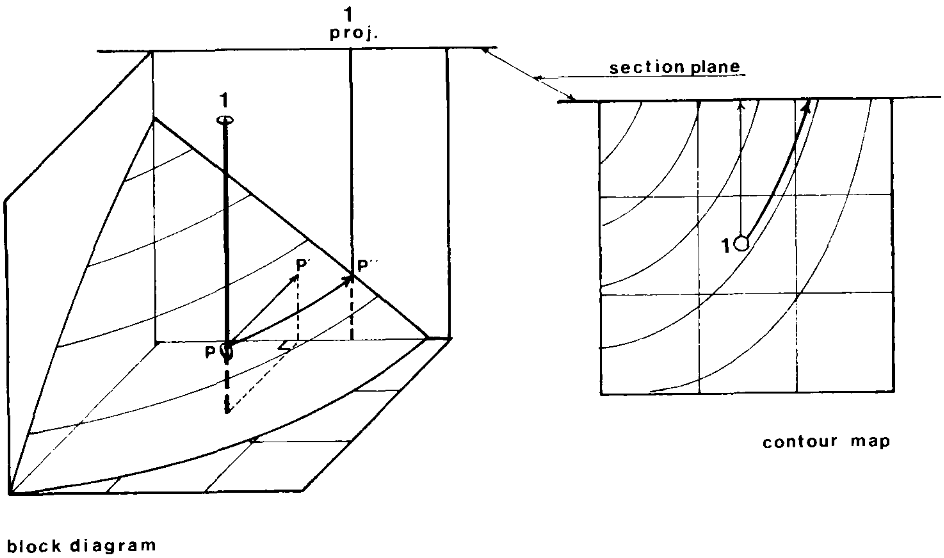
At first sight the simplest method to select cross-sections would appear to be to draw straight lines across the structure, such as line 'S' on the previous page. Such a line would be selected to run close to a number of wells, the data from which could then conveniently be used in the section. Disadvantages of this approach are: the distances between the wells are not those measured directly on the map and the data from the wells are not actually in the section plane but have to be projected into this plane.

These disadvantages can be avoided by constructing sections actually 'through' the wells; in other words, to draw the section lines through the well symbols on the map. At first sight this may be thought to have the disadvantage that the bends or angles in the section will result in bends in the lines representing the intersection with markers and other planes of interest. The figure above shows that this can indeed result in a very unnatural appearance.

However, the nomogram for dip correction showed that corrections for dip angle are negligible if the angle between dip direction and section is less than 20°. This implies also that the 'bend' in a marker line will be so small as to be hardly noticeable if the angle between the direction of the two stretches of section line is less than 20°.

Taking these considerations into account it will be seen that section C3 can conveniently replace section S, without any unacceptable distortion of the structural appearance. Similarly, the other sections are not entirely straight but neither too severely bent.

PROJECTION ALONG STRIKE



In the way described on the previous page the second requirement can be met to a large extent: many of the available wells are represented on a section and on each cross section an optimum number of wells is shown. Nevertheless, some wells are in such positions that they cannot conveniently be included directly in a section. It may then be desired to project the well's data into the section.

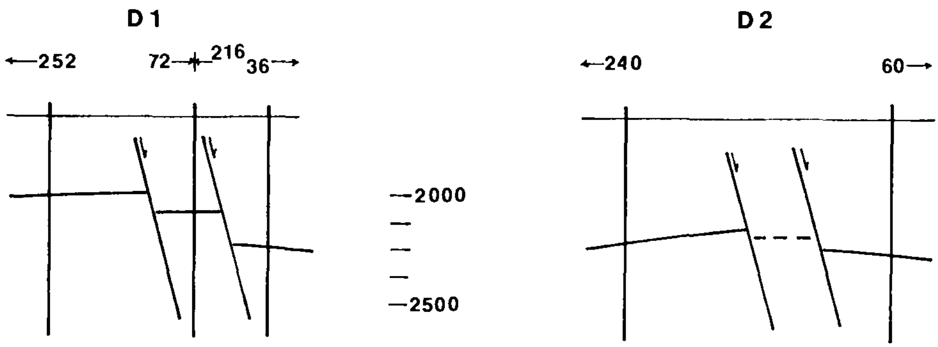
If the well is not at too large a distance from the section line, as for instance the wells that would have to be projected into section S, there is no great objection to such a projection.

The drawing above, however, shows that projection can be seriously misleading. Projection of the penetration point P into the section in the conventional manner, along a line normal to the section plane, brings the projected point P′ to a position well away from the intersection of bedding plane and section, where it should be.

The correct procedure in such cases is to project 'along strike': the point to be projected is, as it were, moved along a strikeline of the bedding plane to the section plane at point P′′. The contour map shows how this is done in practice.

It may be unnecessary to point out that this technique can be applied only for one plane; or for a number of planes, e.g. bedding planes, which are essentially parallel. If, for instance, a fault, with quite different dip and strike, also crosses the well, this crossing point of course must not be projected along the strike of the bedding planes; if at all, it must be projected along the strike of the fault plane itself.

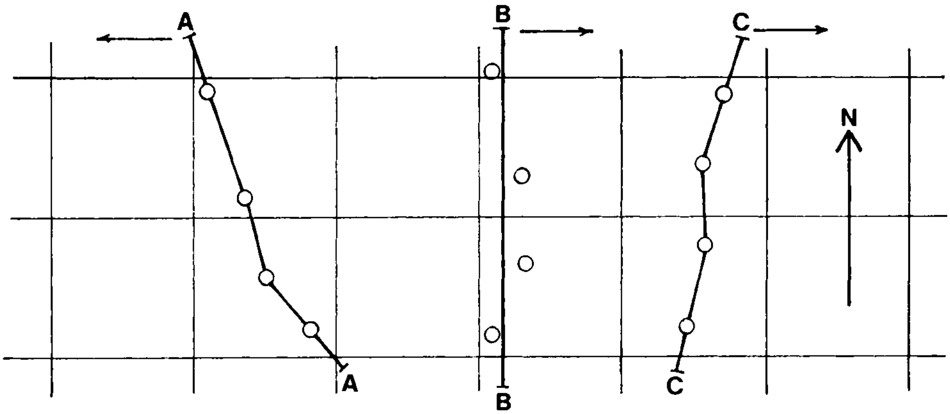
CONTROL



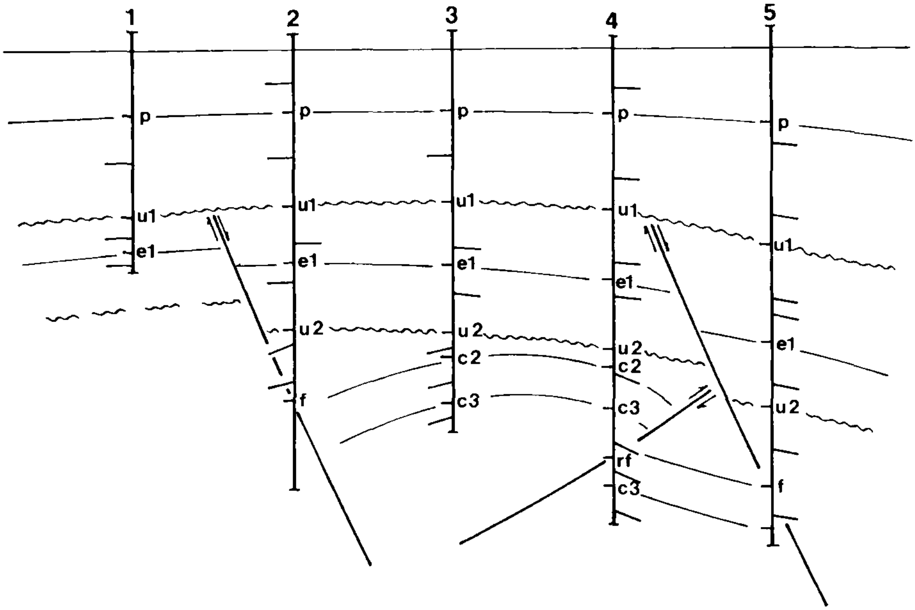
Special sections may be required for the analysis of details of the structure, e.g. D1 and D2 (p. 62). The two sections above show, admittedly quite symbolically, that whereas in section D1 the position of the marker mapped is well defined by the well between the two faults, in section D2 there is no such direct information on the depth in the block between the two faults. Obviously, if one is working to determine accurately the positions of the faults and of the formations in the intermediate fault block, one will select a section with direct well information in the block.

The case may also be used to illustrate the concept of structural control: it is customary to say that in section D2 the control is less good than in section D1. It will be seen later, in Section G.4, that this concept is quite important in its application in oilfield practice.

ORIENTATION



It is probably superfluous to recall the convention that sections are drawn as if looked at from the south. For instance, section A will have its northern end to the left whereas section C has north on the right. A section oriented exactly north-south also has north on the right. It may, however, be advantageous to deviate from this rule if in a series of sections oriented such as section A, one or two members are oriented such as C; this happens often in long elongated fields. To avoid confusion, the few exceptions will then be oriented in conformity with the majority.

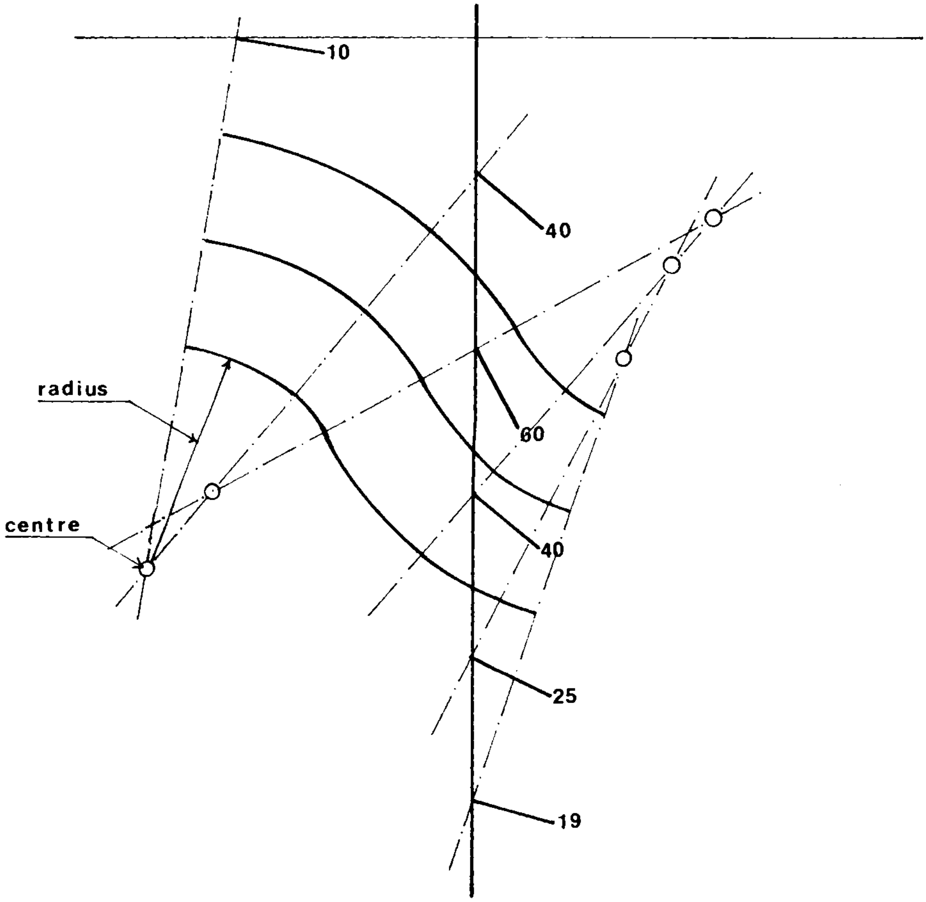


When the section lines have been properly selected and laid out on the field map, the well centre-lines arranged on the section, and all pertinent geological information has been collected and marked on the section, the final stage is the structural interpretation. (In the figure some of the administrative details have been left out to avoid clutter, comp. p. 56.) Starting from the observation points where the wells penetrated markers, faults, unconformities, and using the dipmeter readings, lines have to be drawn on the section to represent the intersections of the section plane with the various planes composing the geological structure.

The procedures for this work are simple: connecting first the marker points, p, u1, e1, etc. as shown in the example above. In most cases this will already yield the main outline of the structural picture in the section plane.

More complex is generally the construction of the fault traces: several different assumptions will probably have to be tried regarding dip and dip direction of the fault planes. It is reasonable to assume, in case of lack of direct information, that a normal fault has a dip of some 65°; to be corrected of course if the dip direction is not in or close to the section plane. Reverse faults can be relatively flat, say, 30°, or steep, close to the vertical (comp. Section C.11). Further questions of course arise: for instance, should the normal faults in the example above cross the upper unconformity?

BUSK'S METHOD



A slightly more sophisticated technique may be used in cases where the dip varies over a wide range along a wellbore.

The dip observations are entered in the section, corrected to apparent dip if necessary. In the example one surface dip reading has been included. At the observation points lines are drawn at right angles to the symbols representing the dip at that point. The lines representing the markers are then constructed as series of arcs of circles, drawn with the intersecting points of the normals as centre points. Because these marker lines are at right angles to the normals at the intersection points the adjacent arcs are continuous at these points and smooth curves result. Obviously, the method can be applied only for folding in which the thickness of the layers is not affected, i.e. the marker lines remain concentric.

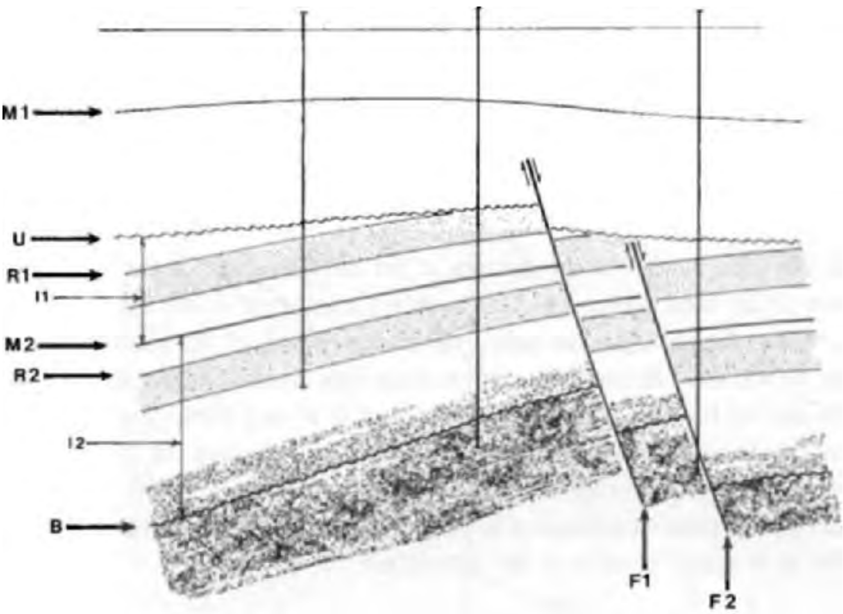
As there exists an infinite variety of geological structures and each structure is unique, it is not surprising that no generally valid techniques for the geological interpretation of the sections can be proposed. The more so as the geologists are also individuals with individual tastes regarding their preferred working techniques.

The structural interpretation of a section is often a matter of carefully puzzling out the various possible solutions and it will be obvious that the selection of the most likely solution depends very much on the conceptual model which the geologist has in mind of the structure he is dealing with, as discussed in Section C.1. In accordance with the principles postulated there, it is also obvious that there will be no unique solution for any individual section and that many question marks will remain.

However, the construction of the sections is but the first stage of the structural interpretation of the field and one section is only a small part of the entire system of sections. When the geologist has taken the interpretation of the sections as far as he can go, he will start on the construction of various types of maps; the sections will serve as part of the basis for this construction. It is very likely that this later stage will reveal shortcomings in the structural picture as adopted for the sections and corrections will then have to be made. Thus, eventually, the whole system of sections and maps portrays a geological structure, which the geologist feels is closest to the reality as it exists invisibly in the subsurface.

C.7 STRUCTURE MAPS

SUITABLE MAP PLANES



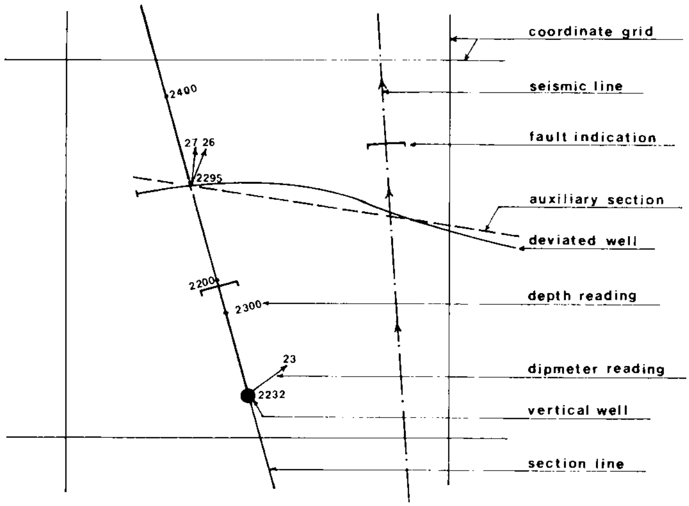
Maps used to depict the subsurface structure of an oilfield can be of many different types. First come those used in that phase of the structural work in which the details of the structure still have to be defined; together with the sections discussed in the preceding pages, these form the framework of the structural picture.

For this purpose one will select to portray planes which are stratigraphically significant, which are well defined throughout the field area and which, preferably, were originally horizontal (comp.Section B.4). Markers M1 and M2, the unconformity U and the, also unconformable, top basement B are in this category. In structures where faults play an important part, and there are many such, fault contour maps are indispensable for the construction of the other contour maps and for the tie-in with the sections.

Both for structural analysis and for construction of contour maps, it may be desirable to prepare thickness maps of suitable intervals. The intervals between U and M2 and between M2 and B are likely to be of interest.

Once the overall structure picture has been worked out to the satisfaction of the geologist, additional maps may have to be prepared. For instance, maps on the tops of the two reservoir zones R1 and R2 are certainly needed for operational purposes; other maps used for reservoir description are to be discussed in Chapter D.

DATA BASE MAP



In preparation for the construction of a structure map, the available data have to be shown on a base map. For proper positioning of the data a coordinate grid is of course the first requirement.

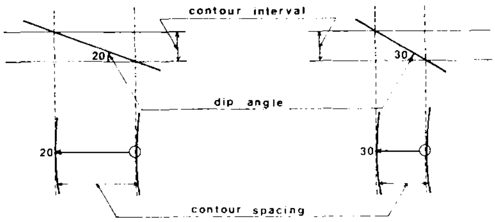
The first data category is the well information: vertical and deviated wells are plotted in order to define the points where the wells penetrate the marker or other plane to be represented. The true vertical depths of these penetration points are shown next to the well symbols. In the sketch it has been supposed that a section has been prepared going through the vertical well and the point where the deviated well penetrates the horizon mapped.

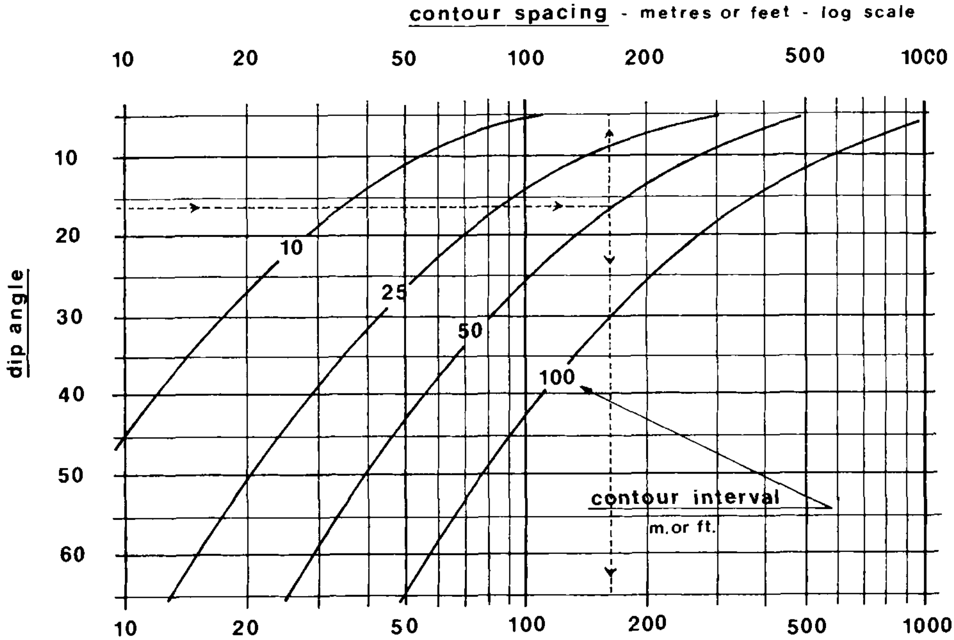
From this section some measured depth points have been transferred to the map, as well as a fault crossing point. It should be remembered that the section is not yet a finished product and is still subject to later change as the structural interpretation develops; the depth points are therefore not strictly 'data', but were only put on the map for convenience. In order to use the data from the deviated well an auxiliary section has been prepared, as explained in Section C.6.

Data from a seismic line are also included. In practice it is rare that a reflector coincides exactly with a plane selected for detailed mapping and therefore no accurate depth points can usually be taken directly from the seismic. In the example only the general dip trend on the seismic line has been indicated by arrows. A fault indication is also shown.

It should be unnecessary to remind geologists that somewhere on the map the horizon mapped should be unequivocally identified and the scale of the map shown. Most organizations have a standard title frame for these purposes, also providing space for such details as author's name, date of map etc.

CONTOUR SPACING



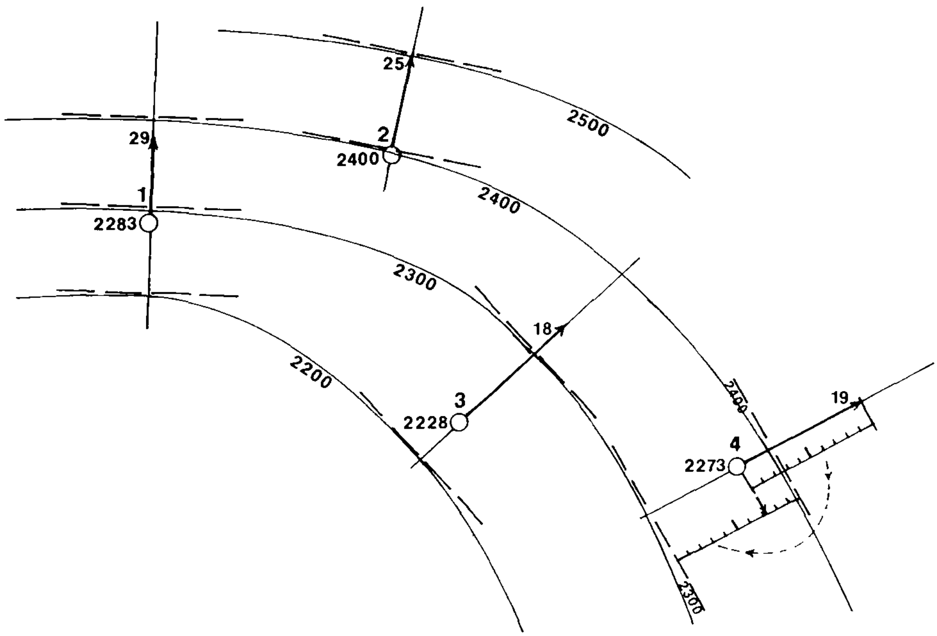


On a contour map the dip of the depicted plane is represented by the distance between the contour lines, i.e. the contour spacing. The closer the contour spacing, the steeper the dip and thus the variation of the contour spacing over the map area gives a good impression of the attitude of the plane in space.

The contour spacing is a function not only of dip angle, but also of the contour interval, i.e. the interval between the depth values represented by the successive contour lines. This interval is chosen for the map, dependent on the prevailing dip values; it is usually reported in the map title.

In plotting dipmeter readings on a base map it is convenient to make the length of the dip arrows equal to – or proportional to – the contour spacing corresponding to the measured dip value. The contour spacing values for a series of dip angles and four commonly used contour intervals can be read from the nomogram. How the system works in practice is shown in the next paragraph.

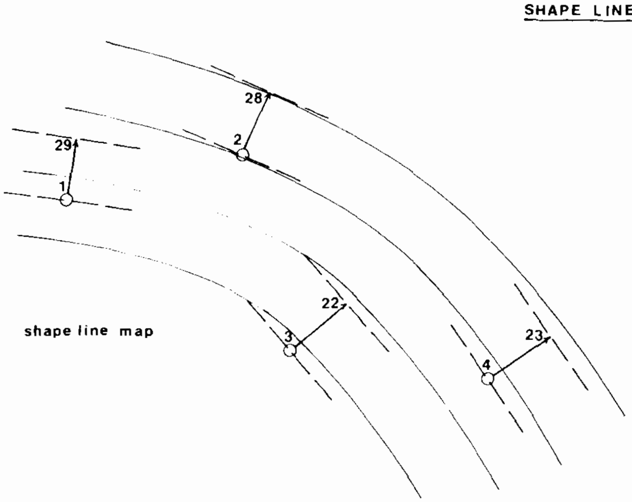
<u>**DEPTH & DIP**</u>

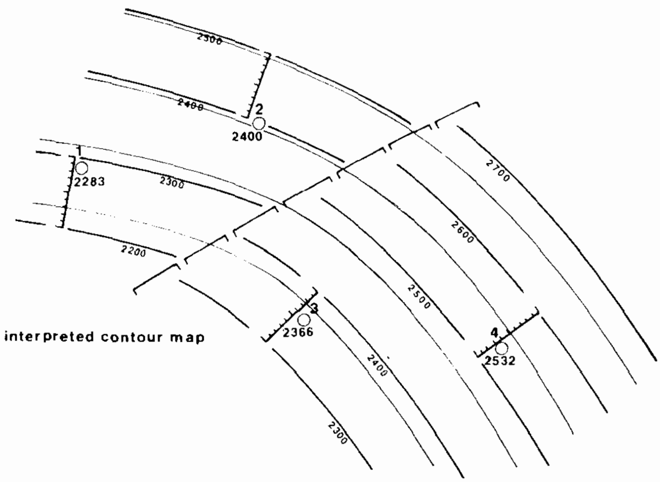


For each well observation point on a contour map in preparation, the depth value is shown and, if available, a dipmeter reading. The contours have to be drawn in such a manner that they are in accordance with these data. A convenient procedure is to start with constructing short straight stretches of 'contours' in the immediate vicinity of the well symbol.

The contour spacing of these contour stretches is given by the length of the dipmeter arrow, if this was plotted as described on the preceding page. This length represents a number of units corresponding to the contour interval used: 100 units (metres) in the figure. The contours have to be drawn such that the depth value of the well comes at the correct interpolated position between them. The figure shows that the dipmeter arrow length can be divided into suitable units, of 10 m each in the figure. This allows positioning the contour stretches properly with respect to the well symbol and they are drawn at right angles to the dipmeter arrow direction. The operation, and several others, can be simplified by using ten-point, multiple dividers (T. Alteneder & Sons, Philadelphia, Pa., USA).

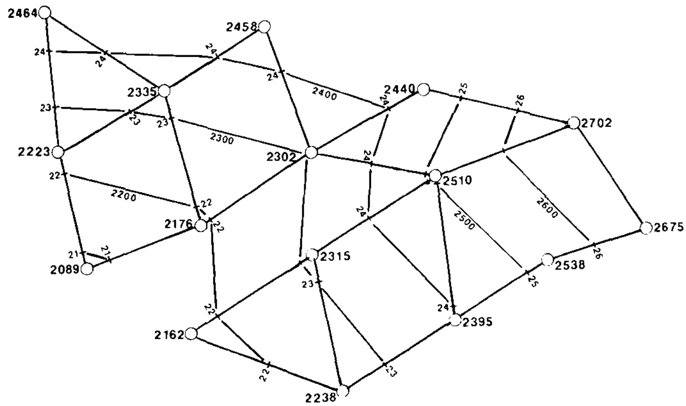
Once this operation has been carried out for each of the wells on the map, the actual contours, as they are to appear on the final map, can be drawn as curves tangent to the straight 'contour' stretches at the point nearest the well symbol.

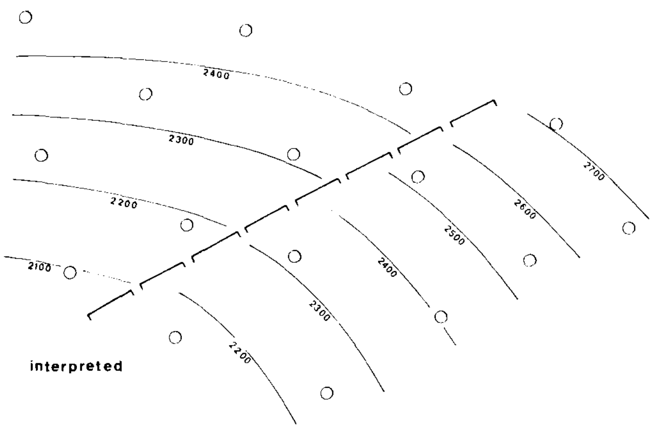




Dipmeter evidence can be used to good advantage by drawing shape lines, based only on the direction and length of the dipmeter arrows, without taking depth into account. The smooth shape lines outline the shape of the structure eliminating local complications, especially faults. As the next step, the depth figures are inserted and the true contours drawn as much as possible conforming to the shape lines. In the example a fault is indicated because the equivalent contours of two areas do not meet on the boundary. It will be seen that the method assumes that the prevailing strike on either side of a fault is essentially the same; this is not necessarily always the case, but may be assumed unless evidence to the contrary exists. Nevertheless, the applicability of the method is limited by this fact.

TRIANGULATION

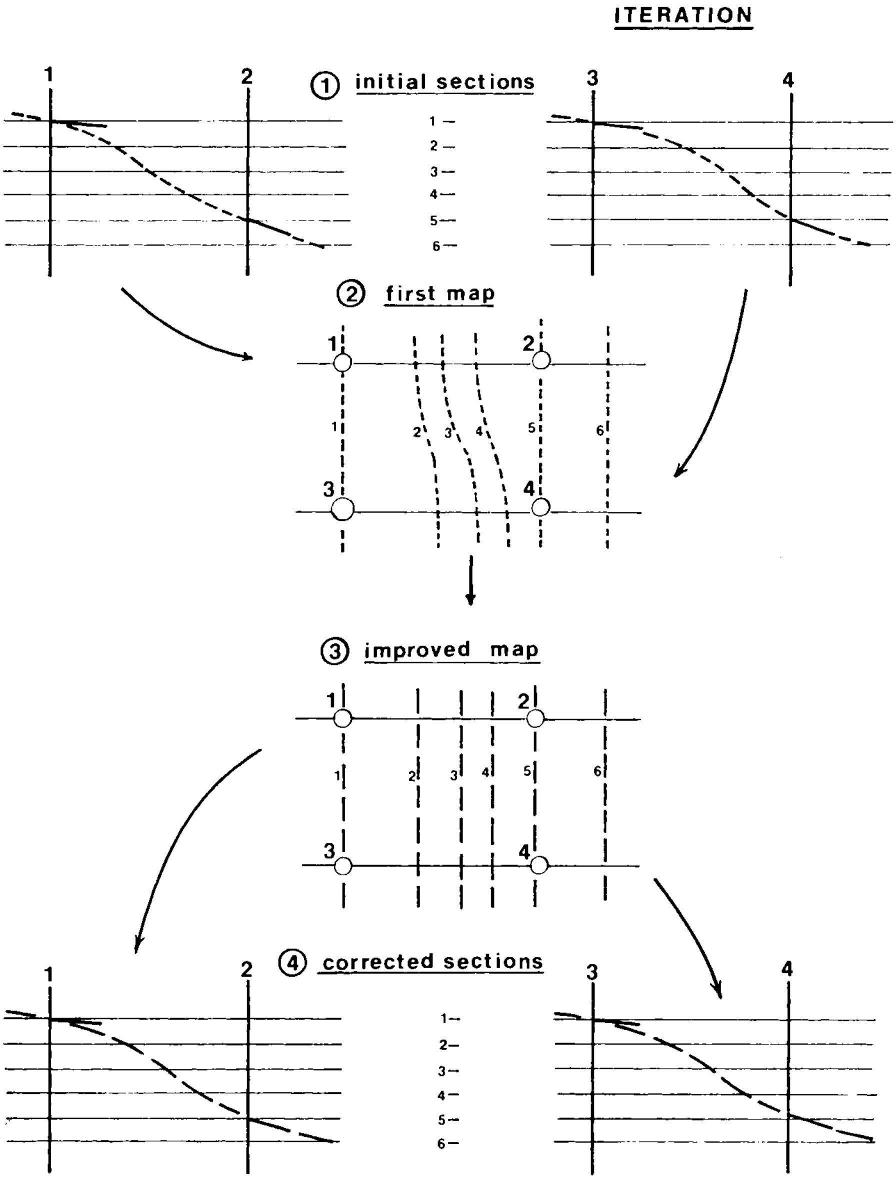




interpreted

The simplest way to use depth information is the triangulation technique. The constructed contours in the example are markedly curved. This may be interpreted as a flexure, but it is more likely that a fault is responsible. This has been assumed in the interpretative map, derived from the 'geometrical' map above. The method obviously is dependent on the number and density of the data points: in a field where only a few and widely spaced wells have been drilled the method is not likely to achieve useful results.

In the example not all possible triangles have been completed; in manual work this is not always necessary: plotting only 'diamonds' is often sufficient. The method is obviously eminently suited for computerization and various programme packages are now commercially available to construct contour maps from numerical data. The geologist will be well advised to acquaint himself thoroughly with the procedure applied in a package before accepting the results as suitable interpretations: the usefulness of the techniques increases with the number of data points and even then may be doubtful if the geological structure is complex.



In the beginning of this section it was mentioned that the structure maps form, together with the structural sections, the framework of the structural interpretation of the field. The construction of a comprehensive set of maps and sections is still the most correct way of defining the structural picture and this is in practice the most frequent of the production geologist's jobs and the one that takes up most of his time.

An important aspect is to ensure that the set of maps and sections is internally consistent. It is a well-known trick for a supervisor, intent on maintaining technical discipline, to check whether maps and sections are in agreement: have the depth points read from the sections been transferred correctly to the map and do the contours conform accurately to these points, do the fault intersections appear in the same spot on map and section?

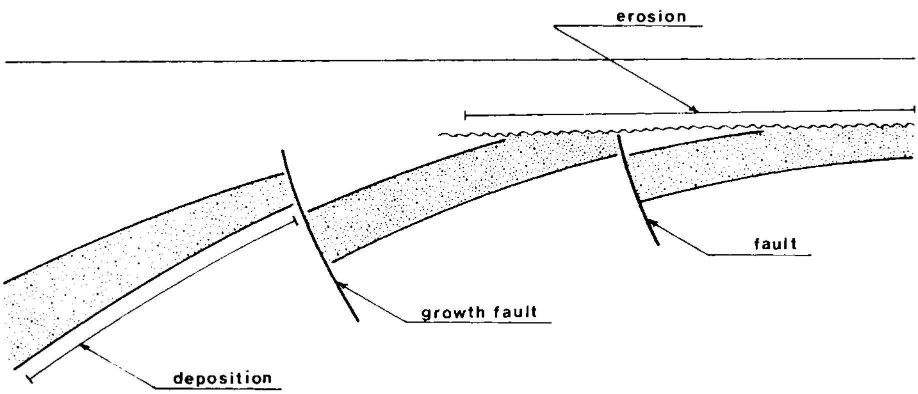
In addition, the picture as drawn must be geologically acceptable. Because no unique solutions are possible in structural work, this acceptability is to some extent a matter of personal taste, based on knowledge and experience.

In order to achieve these two objectives, an iterative procedure has to be followed, as shown in the example on the preceding page. The two initial sections were constructed independently and the interpreted shapes transferred to the map. This first map shows an internal inconsistency: whereas the contours connecting the wells, where structural control is best, are straight, those in the area between these contours are bent, for which there is no justification. The map is then improved by drawing these contours straight and parallel to those connecting the wells. But this means that the sections have to be corrected accordingly.

In the symbolical example this is the end of the procedure: internal consistency and geological acceptability have been achieved as much as possible. In reality it is likely that the geologist will still want to make further changes in the sections, probably to improve the agreement with his conceptual model of the structure; such modifications will then of course require a further correction of the map(s). In this way he will proceed until he is satisfied that he has produced the 'best possible' picture of the tectonics of his field.

C.8 THICKNESS MAPS

THICKNESS VARIATION



Recognizable stratigraphic units are not – necessarily – of uniform thickness. These thickness variations are part of the general geological configuration of a field and should therefore be recognized, mapped and evaluated.

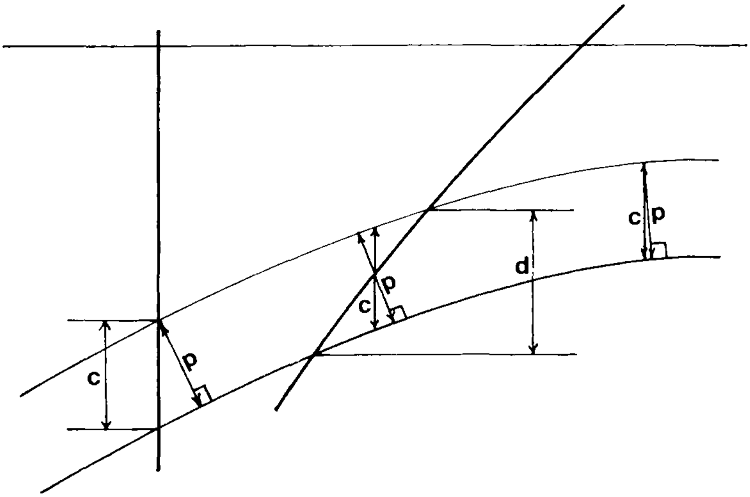
There are various possible causes of thickness variations. Already during deposition more sediment may be laid down in one area than in another in the vicinity. Such depositional variations, by their nature, tend to be gradual and regular. In other cases, however, the changes in thickness are concentrated on the planes of faults, which were active when the deposition of the sediments was going on: so-called growth faults.

In a later stage of the geological development the stratigraphic unit may become exposed to erosion and thickness variations are likely to result, either gradual or concentrated at faults.

In intensively folded formations individual layers are often so strongly deformed that measurable thickness variations result. It is perhaps not too exaggerated to say that such intensive folding is rare in oilfields.

Thickness maps are often useful in the analysis stage of the structural work in an oilfield, especially in the locating and definition of faults, because abrupt thickness changes across faults are often easily recognizable. It will be seen later, in Chapter D, that thickness maps are mainly of use in sedimentological work.

ISOPACH & ISOCHORE



Two types of thickness maps are used in production geology.

The *isopach* map depicts the variations in true stratigraphic thickness of a unit, marked p in the above figure (assuming the section is a true dip section!). Isopach maps are mainly useful for sedimentological studies.

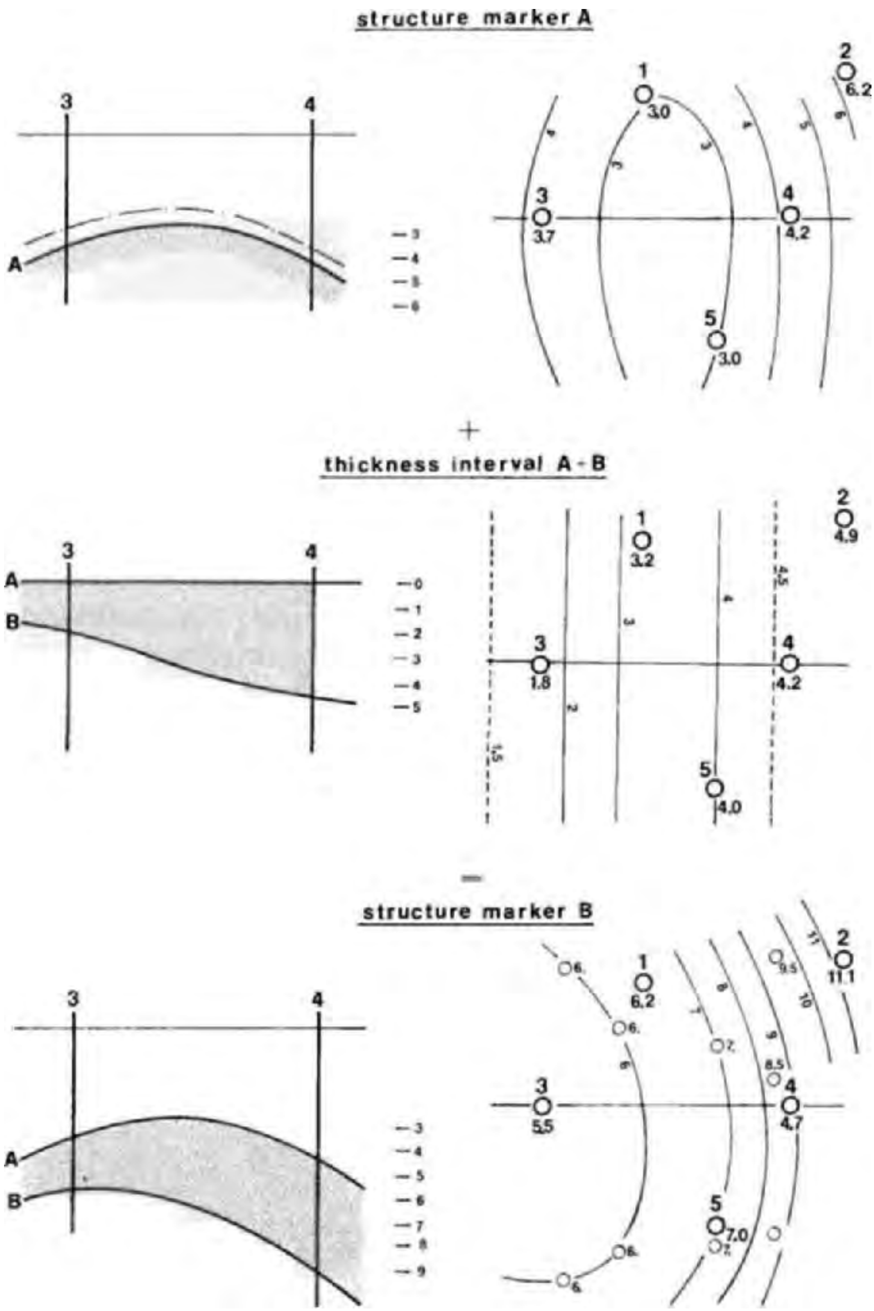
The *isochore* map shows the vertical distance between top and bottom marker of an interval, marked c in the figure. It is mostly used for work in tectonics, as further discussed below.

The right-hand side of the section shows that the difference between isopach and isochore becomes negligible with small dips, say, below 10°.

To calculate the correct thicknesses from data of a deviated well is a complex problem in solid geometry; certainly the difference between the TVD's of top and bottom penetration points in the wells is not the correct parameter to be used, as shown by the distance d in the figure.

The exercise need only be carried out if great accuracy is desired. In practice, this is probably rarely justified, because of existing error margins caused by other effects. The simplest alternative method is to construct a simple auxiliary section (see p. 57) along the course of the deviated well, using the dipmeter readings (corrected to the section plane if necessary), to construct top and bottom markers, from which the correct thicknesses can then be read with sufficient accuracy.

ISOCHORE ADDITION



Isochore maps can be very useful aids in structural mapping, largely because thickness maps are in most cases more regular and therefore more easily constructed from scattered well data than structure maps. The procedure is sketched above. A structure map is drawn on marker A, in this case supposedly with the support of a nearby seismic horizon. The interval to the next lower mappable marker is then mapped as isochores. When the resulting map is superimposed on the marker A structure map, values for the depth of marker B can be easily read off at the crossing points of contours and isochores; these additional data points are then entered on the base map for the structure map on marker B (ref. small circles in the figure). The structural contours on marker B can then be drawn more easily than would have been possible on the basis of the well data alone.

This method of isochore addition lends itself very well to computerization. Programmes for the construction of – any kind of – contour map by computer generally work on the same fundamental principle: the area to be mapped is overlaid with a regular grid of points. At each grid point the value of the parameter to be mapped (structural depth, thickness, but also porosity, etc.) is computed by some form of interpolation from a number of nearby data points (in our case wells). The machine then draws 'iso-X'-lines based on these regular grid data points.

Clearly, once, say, a structure map on marker A is stored in the memory and also a thickness map of the interval A-B, the computer can conveniently add up the two parameter values for each grid data point and thus obtain a grid of values representing the depth of marker B. On this grid the structural contours for marker B can then be drawn, by machine or by hand.

As was mentioned before (p. 75), the validity of such computer methods increases with the number of data points, in other words with the density of the geological control. On the other hand, the more complex the geological structure, the greater the chance that the computer method will produce a map which is not 'geologically acceptable', in other words does not satisfy the geologist that it really represents the most likely geological picture.

In general, the application, or otherwise, of computer methods is a choice that the geologist must make on the basis of his knowledge and experience and on the peculiarities of the structure he is dealing with. In any case the results of a computer operation must be examined critically and be left open to modification by hand if this should improve the geological credibility of the maps.

C.9 MISCELLANEOUS DIAGRAMS

In addition to the maps and sections discussed in the preceding pages, various other types of drawings may be useful in special circumstances or for special purposes. A few of these will be mentioned in the following paragraphs.

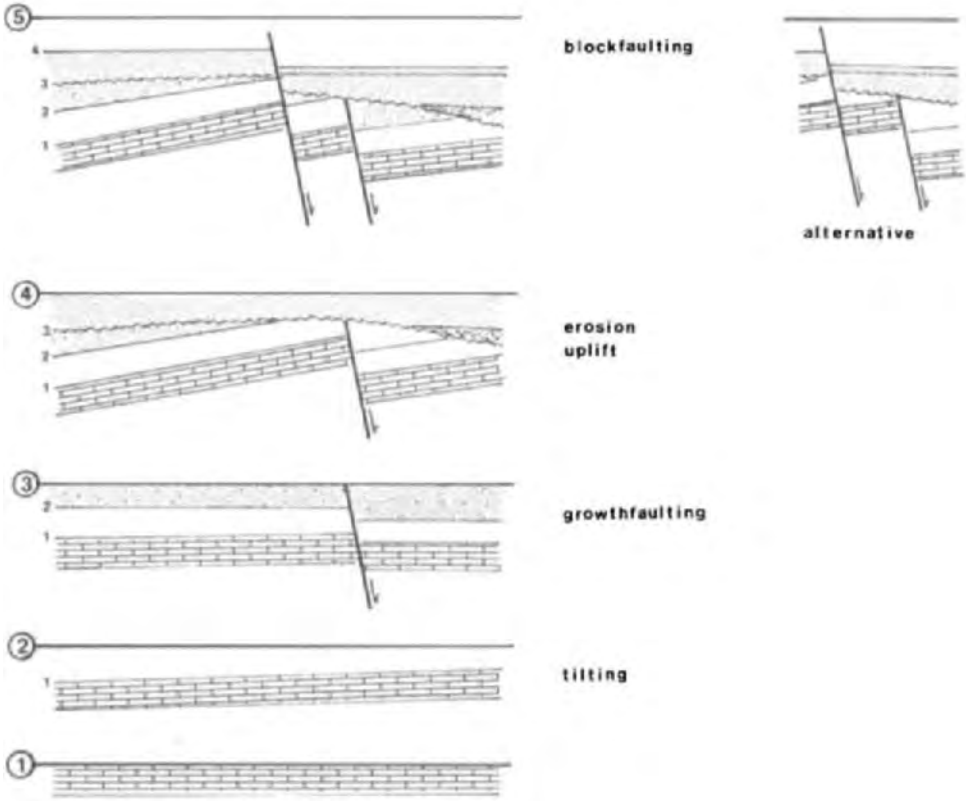
For the proper description of a structure in which faulting plays a significant part, the construction of a fault map will be indispensable. Such a map is in fact a contour map on the fault planes and is used to construct the intersections of the faults with bedding planes or markers on which contour maps are to be drawn. The procedure will be discussed further in Section C.11.

It may be useful in some cases of complex structures to facilitate the unravelling of the tectonic structure by means of one or more 'horizontal sections'. These diagrams represent the geological situation in a flat horizontal plane through the structure, just as normal sections represent the structure in flat vertical planes. In tectonics work the horizontal section is a useful means to check the internal consistency of the structural picture.

A horizontal section – also known as level map – can be quickly constructed by copying contours of equal depth value from a series of structure maps on different horizons and faults. The resulting map is very similar to a surface geological map made by a field geologist, which is also a cut through a structural situation on an – essentially – horizontal plane. A trained geologist will quickly detect any inconsistencies in the pattern of equivalent contours, which in fact outline the 'outcrops' of the various stratigraphic units on the horizontal plane represented by the map. The use of level maps in reservoir geological work will be discussed in Chapter D.

Block diagrams are a favourite means of illustrating a structural situation in many fields of geology. In production geology they can also have their uses in facilitating the visualization of intricate three-dimensional situations; for instance, to help staff in realizing the shape of a reservoir and the consequences which the peculiarities of this shape may have from a technical point of view. However, block diagrams have disadvantages in view of the consideration that production geological diagrams are generally to be used as technical working drawings, rather than as illustrations. Because of the distortion of reality, inherent in the construction of block diagrams, it is usually not possible to measure angles and distances with any accuracy from a block diagram; this limits its use to the purely illustrative.

HISTORY



Another useful aid in the structural analysis is the examination of the tectonic history of the structure. This can be done with the help of a series of sections, each showing the situation at the time of the deposition of a specific marker. Such sections are constructed by using the successive markers as datum and reconstructing the underlying formations. Thus the series of sections shows the change from the original horizontal position of the marker to its present-day deformed condition in some detail.

In some cases the historical analysis can also help to check on the likelihood of the structural model. Assume, for instance, that the structural position of the central fault block, between the two faults, in the final section is not known from direct geological control. Perhaps the contour map on marker 1 requires a position of this marker as shown in the alternative. In this interpretation, marker 2 is preserved on both the adjacent fault blocks, but not on the central block; this implies that the central block has been eroded more deeply than the other two blocks, in other words, has been uplifted at one time higher than the other two blocks but has since subsided again to a lower position than the west block. Such inversions are of course not unknown but it is more probable that the situation is as shown in the other section. If this interpretation is adopted, the structure map on marker 1 would of course have to be corrected.

Such a historical analysis can be elaborated by introducing the third dimension: instead of a series of sections, a series of thickness maps is drawn representing successively the interval between a specific marker and a basal marker. This allows defining such items as: tilting directions, erosion effects, etc.; and is often helpful in locating faults, the exact position of which was not previously well-defined.

Once the structural picture of the field has been worked out to the satisfaction of the geologist and properly documented with the necessary maps, sections and other diagrams, it may be necessary to produce other maps for illustrative or, more probably, for operational purposes.

The most common need is probably for maps which accurately portray the shape and positions of the reservoir or reservoirs in the field. At the very least a well-defined structure map on the top of the reservoir will be required. If the thickness of the reservoir zone – i.e. the stratigraphic unit in which the oil and/or gas are contained – is markedly variable, a map on the base of the reservoir will also be needed, in order to facilitate the accurate estimation of the reservoir volume (comp. Chapter J).

In many fields the total reservoir zone is subdivided into several individual subzones, which may in fact constitute separate reservoirs and will therefore be exploited separately (ref. Section F.5). In such cases maps on the tops, and possibly also the bases, of these subzones will also have to be made.

C.10 STRUCTURAL STYLES

> 'Almost all geologic structures, if viewed in enough detail, have unique geometries and histories. On a more regional scale, however, certain general characteristics define broad categories of structures'.
>
> Harding, T.P. and Lowell, J.D., 'Structural Styles in Petroleum Provinces', Bull. AAPG V.63, No. 7, July 1979.

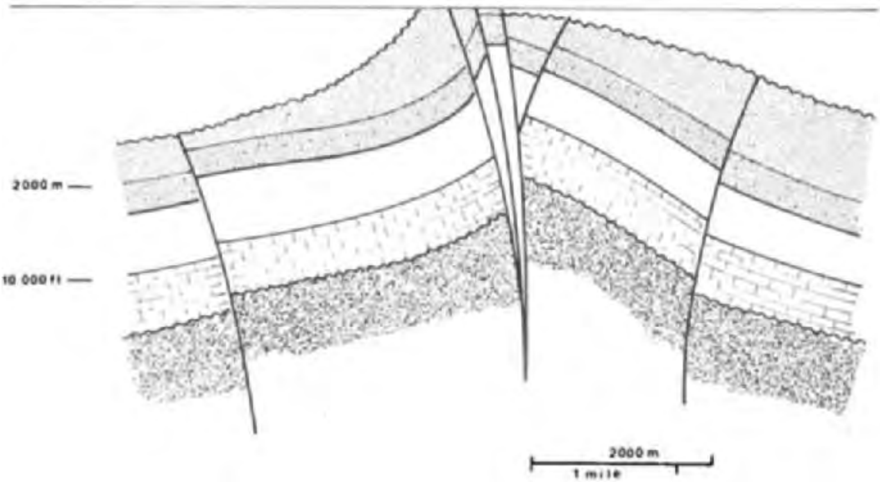
If the statement quoted above were not true, the work of the production geologist would be much more difficult, if not, in extreme cases, impossible. It was indicated in the beginning of this chapter that the geologist in attempting to define and depict the subsurface structure in his field, has in mind a model of what the structure is likely to look like. Such conceptual models are possible only because individual structures, although to some extent unique, tend to have certain characteristics in common.

These common structural styles result from the similarity of the mechanical conditions which shaped the structures from the sedimentary raw material. As these mechanical conditions tend to be similar over areas, such as geological basins or petroleum provinces, the structures occurring in such areas are likely to be similar. But not only that, there are different areas in the world where the geological history and therefore the mechanical conditions are similar and in such areas similar structural styles are likely to prevail.

In structural geology many attempts have been made to arrive at definition and classification – on a descriptive or genetic basis – of such structural styles. It is from this knowledge that the practicing production geologist derives the conceptual models which he needs for his analysis and description of the tectonics in his fields. When entering a new field, he will refer to the existing structural pictures of fields in the immediate vicinity. And even when going into a new area, he will probably be able to find another, older petroleum province where a similar geology prevails and from there he may be able to borrow a suitable tectonic model.

It is obviously not within the scope of this book to attempt another description or classification of structural styles. For purely illustrative purposes a few of the more common structural styles of major petroleum-producing areas are shown in the following pages.

WRENCH FAULT STRUCTURE

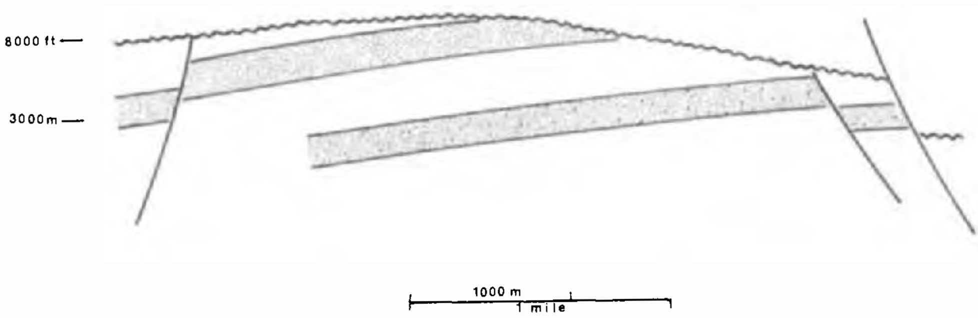


The production geologist is, ex officio, interested in oilfields. This means that the subjects of his study are small compared to what most geologists work with: individual oilfields are rarely more than, say, ten kilometres or six miles long and five kilometres, three miles, wide. Moreover, as the oil or gas is commonly accumulated in the structurally high parts of an area, the production geologist has a detailed knowledge of uplifts, anticlines, high parts of faults blocks, but generally he has little information on the structurally low-lying areas outside the highs. The examples of structural styles shown on this and the following pages therefore are restricted to common types of oilfields, without attention being given to the regional setting.

In the practice of applied subsurface geology it is generally very difficult, if not impossible, to determine with certainty whether a fault is a wrench fault (= transcurrent fault). Movements along faults more or less in the direction of the dip of the fault plane are generally not difficult to establish, but lateral or tangential movements of two fault blocks with respect to each other are much more obscure. Hence it is largely on the basis of the general appearance of the structure that the above example has been brought into the class of wrench-fault-determined structures.

The fact that basement is involved in the structural deformation, implies that the main faults are probably of regional importance and that the anticlinal uplifts on which the hydrocarbon accumulation took place are aligned along these faults and obviously genetically related to them.

EXTENSIONAL BLOCKS

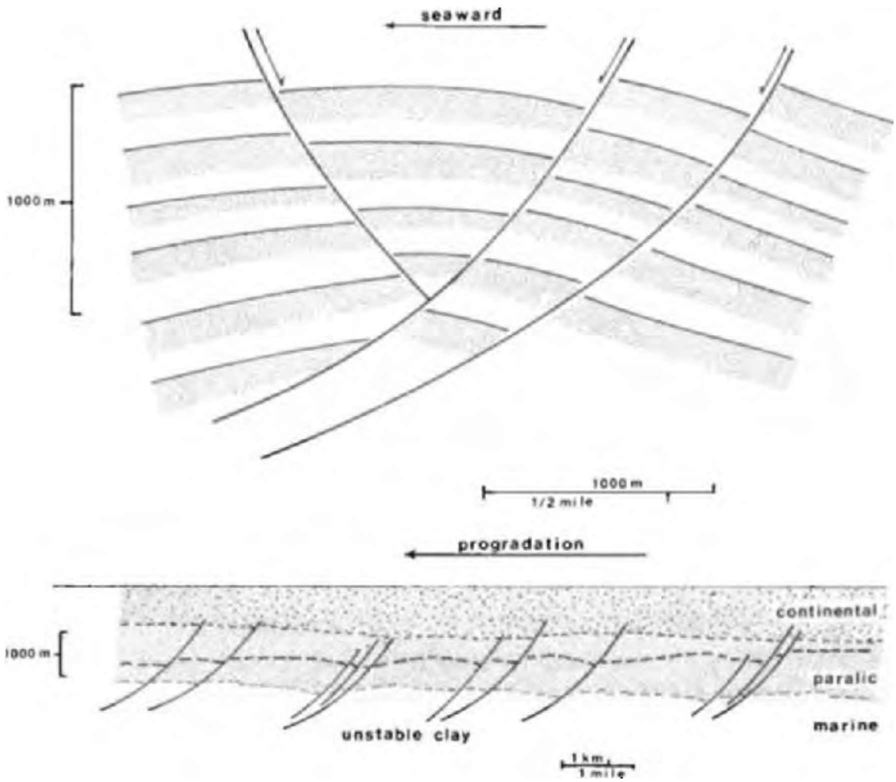


Several oil-producing areas are related to rifting situations of the crust. The accumulations are then generally contained in blocks between major fault zones. These blocks are tilted, mostly at relatively low angles, but otherwise little deformed. The main limiting faults are generally subparallel to the axis of the rift graben and basement is involved in the block-faulting activity.

From the viewpoint of the production geologist the main problem in the study and development of fields in such areas is the unravelling and definition of the pattern of subsidiary faults that affect the blocks between the main faults. These subsidiary faults are difficult to locate, because their throw is mostly rather small, in the order of a few tens of metres. Nevertheless, they are important in the context of field exploitation, because they can often be shown to divide the field into several reservoirs, which are wholly or partly sealed-off from each other by the faults. It is therefore most important to locate the faults as accurately as possible.

The faults often occur in more or less well-defined systems of parallel faults. These are either parallel to the major rifting faults or run at angles to them. Such systems will be discussed somewhat further in Section C.11.

GROWTH FAULT & ROLLOVER

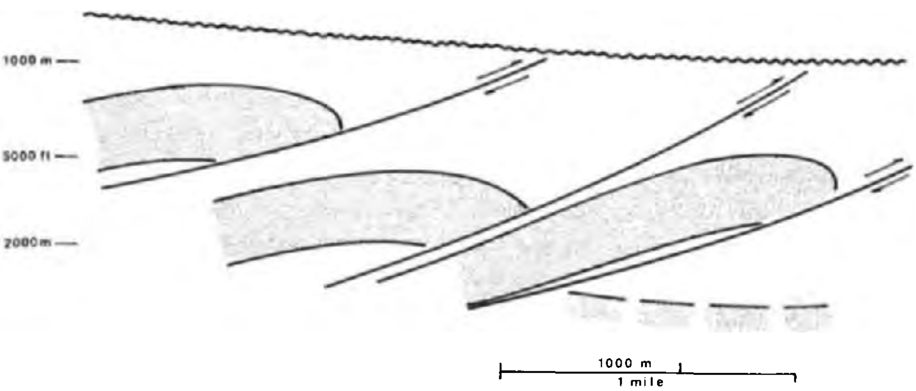


Deltaic formations are a favourite habitat for hydrocarbon accumulations. As major deltas prograde seaward (lower section), masses of paralic and, subsequently, continental sediments are deposited on a substratum of proximal, marine, mainly argillaceous deposits. Under the influence of the overlying sediment load, these marine clays become mechanically unstable, with as a consequence sliding movements in the paralic deposits. Shovel-shaped faults develop, mostly downthrowing 'to the coast' and on the downthrown side of these faults the regional dip is locally replaced by the opposite dip. These 'rollovers' contain the hydrocarbon accumulations. As the movements take place during the deposition of the paralic sediments, the faults are all growth faults.

The upper section shows, schematically, a detail of a rollover structure. The paralic series consists of alternating sands and clays, but the actual sand-clay distribution is more complex than is shown in the figure: the units in reality are thinner and would thus be more numerous in the same interval thickness. The overlying continental formations consist mainly of sand with subordinate clay intercalations.

The map on p. 62 shows a typical rollover structure, in map view.

THRUST FAULTS



Another environment in which important oil provinces have been found, are the intricate thrust belts, dominated by low-angle reverse faults and often related to major mountain chains.

From the production geologist's viewpoint, the thrust fault structures present serious problems. Because the imbricated units often partly cover each other, it is difficult to locate the crests of the individual highs on which the accumulations are located. Seismic is in many cases of little help because of the intricacy of the structures and the multiplicity of reflecting horizons above each other. Moreover, even when the crest of an imbrication unit has been located on one section, by seismic and drilling, there is often little evidence regarding the lateral extent of the unit, i.e. along the strike of the thrust fault. Careful 'outstep drilling' will often be required to establish the length of the reservoir or field.

Apart from the four structural styles illustrated, there are other styles in which oilfields commonly occur.

Already in the early stages of the history of the oil industry, much attention was given to structures related to salt domes. Either the dome-shaped structures overlying the salt, resulting from the upward growth of the salt mass. Or the piercement structures, where the growing salt dome or pillar actually pierces the adjacent sediments. Both types exhibit intricate fault patterns which show little evident system and are consequently difficult to predict.

Structures not too dissimilar from those overlying salt domes can be formed over 'shale domes'. These argillaceous masses can form in formations of unstable clay, similar to those underlying the deltaic growth fault and rollover structures, but not in such a position that these sliding effects are realized.

The wrench fault structures mentioned are often not easy to distinguish from other structures related to steep reverse faults, without the lateral movement. Such dip-slip reverse faults can conveniently be called upthrusts. Because the geometry of the structures resulting in either case tends to be quite similar, it may not be too important in practice what the actual origin of the structures was.

C.11 FAULTS

Faults are extremely important elements in oilfield geology. A fault, or a set of faults, can be the main trapping agent to which the existence of a field is due in the first place. In other cases faults can be barriers separating individual reservoirs in a field. Or they can, in contrast, be communicating channels between different parts of a reservoir (ref. Chapter F). They can unexpectedly limit accumulations to a smaller volume than had been foreseen; or, in favourable cases, they can cause unexpected extensions.

Obviously, the recognition, definition and accurate mapping of faults within an oilfield is of first importance. Unfortunately, faults have a number of characteristic properties which make them into difficult elements to work with in the structural analysis:

Faults are generally steep planes, say, between 50 and 80 degrees in the majority, and thus have a small chance of being hit by a (vertical) well. This in contrast to stratigraphic horizons (markers, etc.), which in oilfield practice are rarely steeper than, say, 30 degrees.

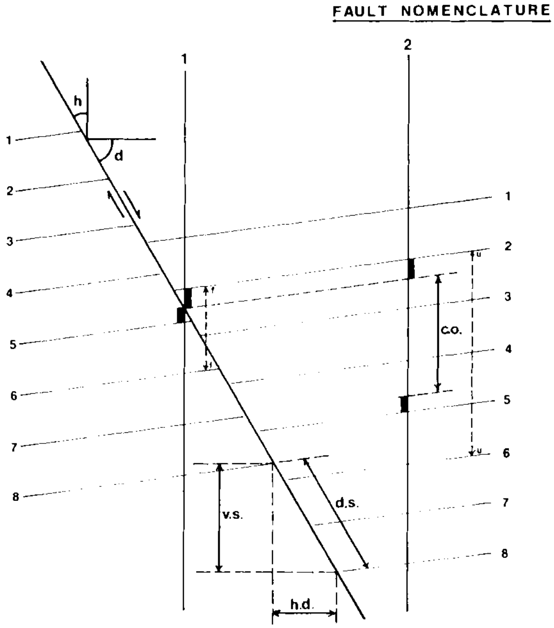
Stratigraphic horizons, by definition, have individual recognizable characteristics which allow identification from well to well; the process of correlation is based on this fact (comp.Chapter B). Faults have no such characteristics, so if two wells penetrate the same fault there is little or no factual evidence to say that it is indeed the same fault.

There is one property of faults which can, in most cases, be established and quantified at the observation point in a well: the magnitude of the throw of the fault (ref. p. 92). However, unfortunately, this parameter is variable both laterally and with depth along the fault plane and is therefore not very useful as an identifying characteristic.

Fault planes are rarely visible as such on seismic sections, as discussed in Section C.4. Such guidance as the production geologist may have from seismic is therefore itself interpretative and not strictly factual.

Dipmeter readings on fault planes are rare (ref. Section C.3); at best some indication of dip and strike of the fault plane can be derived from dipreadings reflecting the drag pattern along the fault.

In conclusion: the factual evidence regarding faults is rarely sufficient to establish a cogent and binding fault pattern as part of the general structural interpretation. Resort to conceptual models is not easy, partly because little formal research on fault geometry and patterns has been done.The following discussion is therefore little more than a number of remarks stemming from practical experience.



The figure illustrates a number of parameters which are used in the description of faults:

The *dip*, as usual, is the angle between the fault plane and the horizontal, angle *d*. For faults the complement of this angle, i.e. the angle with the vertical, is often used: the *hade* (angle *h*), reputedly an English miners' term.

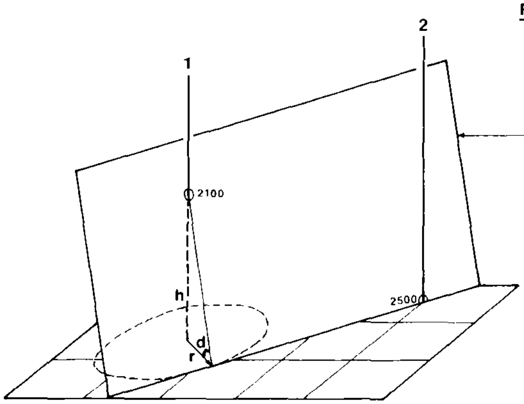
The magnitude of the fault is measured by its *throw* or *vertical separation* (v.s.): this is the vertical distance between the intersection points of the fault with equivalent markers on either side. This parameter can be read directly from contour maps, which is convenient. The distance between the same points measured along the fault plane is the *dip slip* (d.s.), whereas their horizontal distance is the *horizontal displacement* or *heave* (h.d.).

The stratigraphical importance of the fault is measured by the magnitude of the stratigraphic gap, or *correlation gap* or *cut-out* (c.o.): the log of well 1 shows that this gap corresponds to the interval from a short distance below marker 2 to a short distance above marker 5. Numerically the cut-out can be measured as the difference in distance between equivalent markers unfaulted (u-u) and faulted (f-f).

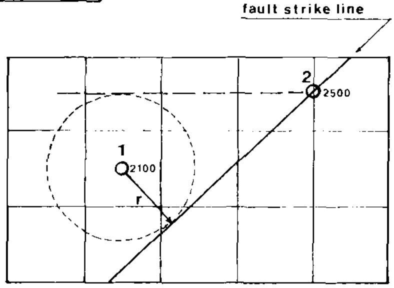
Mutatis mutandis the same definitions apply for reverse faults.

It may be objected that the measurements indicated are not exactly accurate if the dip direction of the layers is not the same as that of the fault and perhaps not the same on either side of the fault. In most cases the inaccuracies are probably no worse than other inaccuracies which are inevitably included in the correlation.

FAULT PLANE CONSTRUCTION



fault strike line



$r = h \cdot \text{cotan } d$

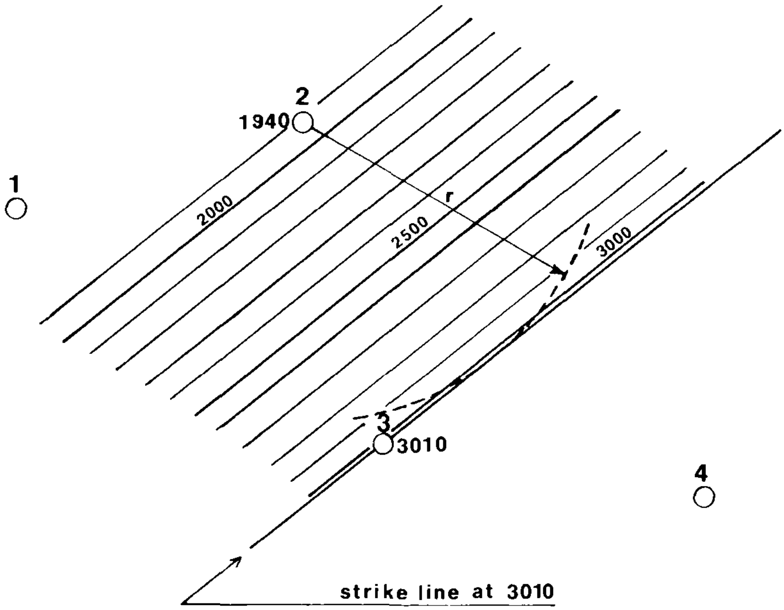
A minor, but frequent, problem is the determination of the position of a fault plane from two observation points. The diagrams represent two wells which penetrate the same fault at different depths. The problem is to construct a strike line, i.e. the intersection of the fault plane with a horizontal plane.

The solution makes use of the fact that the locus of a plane with a certain dip passing through a certain point, is a cone with the point as apex and the complement of the dip angle equal to half the apex angle of the cone. All planes tangent to this cone satisfy the condition. The figures show that this cone constructed around well 1 intersects the horizontal plane through the penetration point of well 2 as a circle. The required strike line then passes through the penetration point in well 2 and is tangent to this circle. (There are two such lines, one representing a dip of the fault roughly to the southeast, the other to the north; this possible choice should present no difficulties in most cases.)

The radius of the circle is determined by the difference in depth h between the two penetration points and by the dip angle. If the dip angle is known – or a likely assumption can be made – the cotan of the dip angle can be looked up. It may be simpler to construct a simple section representing the triangle with side h and the dip as its base angle.

If there is no evidence regarding the dip of the fault it is convenient to assume an angle of about 63 degrees, the cotan of which is 0.5, i.e. r equals half of the depth difference h.

FAULT MAP

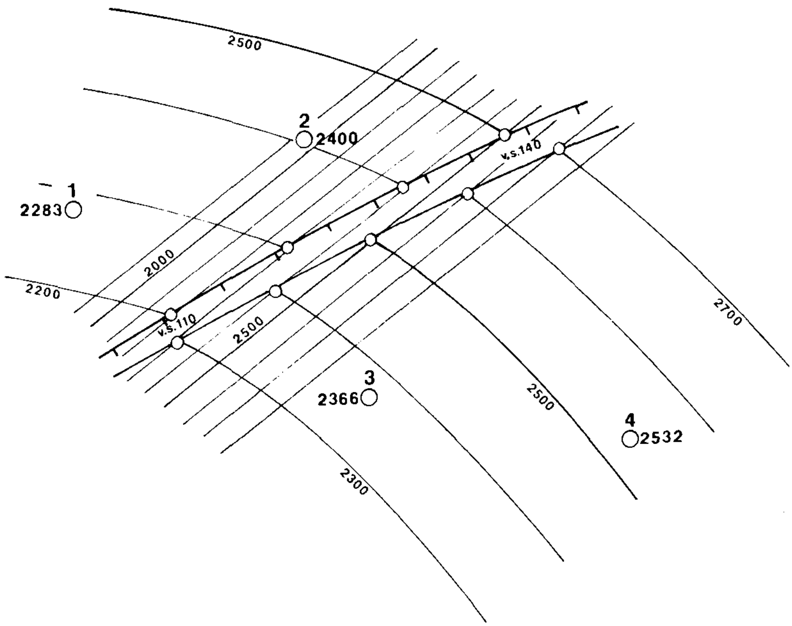


The fault map was mentioned before as one of the maps which are likely to be needed in addition to the structure maps on stratigraphic horizons, markers, etc. A fault map is nothing else than a structural contour map on all fault planes in a field. It is needed in the first place in those fields where a more or less intricate fault pattern is present; the map will there be useful as a check on the consistency of the fault interpretation. In addition the fault map is to be used in constructing the fault traces on structure maps of stratigraphic levels intersecting the fault; this aspect will be discussed on p. 95.

The figure above shows a detail of a fault map. Two wells have penetrated a fault at 1940 m and 3010 m, respectively; the two fault penetrations are believed to represent the same fault. The dip of the faults in the area is in the order of 63 degrees.

The construction method dealt with on the preceding page has been used to define the strike direction of the fault plane. The depth difference between the two observation points is 1070 m; hence the radius of the construction circle equals 535 m (on the scale of the map). The spacing of the contours on the fault plane is determined by the usual interpolation procedure between the penetration point of well 2 and the strike line at depth 3010 m. The contours on the fault plane are then drawn parallel to the strike line.

FAULT TRACE



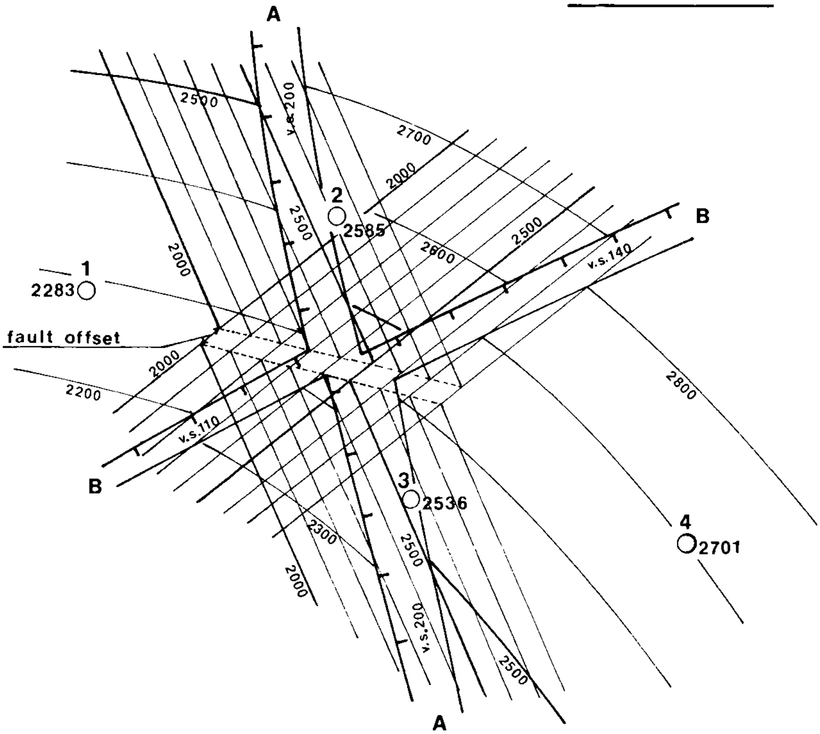
Where a stratigraphic horizon is intersected by an inclined normal fault, the contour map on the horizon will show the fault trace as a strip where the horizon is not present. This strip represents the *fault gap*; if a well is drilled into this strip it will not encounter the mapped horizon. Naturally, the larger the throw of the fault is, the more important the fault gap will be in the geometry of the mapped horizon.

The figure shows the simple way in which this situation can be mapped with accuracy: the contour maps on the horizon and on the fault plane are superimposed and the intersection points of the equivalent contours are marked. This results in two lines of intersection points, representing respectively the fault trace on the high block and on the low block.

The importance of the fault can be judged conveniently from this map: the throw or vertical separation at any point along the fault can be read off from the depth values on the horizon on opposite sides of the fault gap. The distance between the two trace lines is equal to the heave of the fault at that point. The heave in turn is determined by the throw and the dip angle of the fault; if either of the two parameters or both varies along the fault, the width of the fault gap will vary as well.

The same technique can be applied in the case of a reverse fault but the result is an overlap of the two sides of the fault instead of a gap.

INTERSECTION

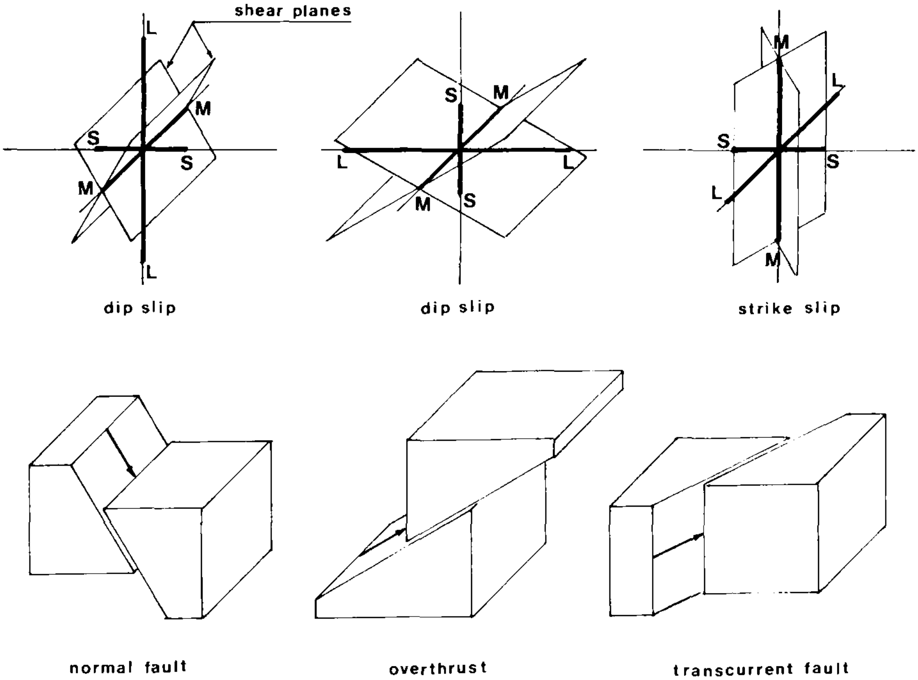


In order to illustrate the intersection of two fault traces on a contour map, it has been assumed that before fault B originated an older fault had existed, throwing down in an easterly direction by an amount of about 200 m. The figure shows the graphic operations carried out to depict this situation on the contour map of a stratigraphic horizon.

The contours on the plane of fault B are the same as in the figure on p. 95; for the contours on fault A the same dip of 63 degrees and an arbitrary strike have been postulated. The construction of the intersection of the two faults is of course the same as for a fault and a stratigraphic horizon.

The field geologist is accustomed to the situation where the outcrop line of an older fault (A) is offset by that of a younger fault (B). This configuration is also seen in the equivalent contours on the two faults; for instance the 2000 m contour on A is offset by the same contour on B. (A surface map can of course be seen as a map at depth zero and the surface outcrop lines are contours at depth zero and will show the same offset.) It must be noted that by contrast the fault traces on the contour map of the stratigraphic horizon do not show this same offset but a quite different picture from which the age relationship cannot be read immediately; a trap for the unwary!

FAULT TYPES 1

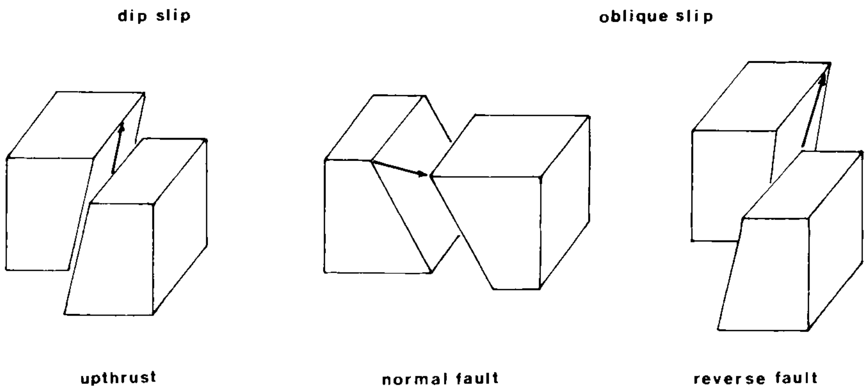


The classical subdivision of faults into types is – for the sake of completeness – illustrated above. If a part of the earth's crust is subjected to tectonic forces, a stress field is set up in the rocks which can be described at any point by a three-axial ellipsoid with three unequal axes: Largest, Medium and Smallest. The simplest assumption is that one of the axes is vertical, the other two horizontal; this allows three fundamental, different positions as shown.

If the stress differences are large enough, the cohesion in the rock may be broken along conjugate sets of shear planes. These planes contain the medium stress M and the angle between the planes is bisected by the largest stress L. The angle between the planes depends to some extent on the mechanical properties of the rock material but is generally around 60 degrees.

The shear planes can develop into faults, if finite movements take place along the fracture planes. The three fundamental positions of the stresses lead to three different fundamental types of faults.

FAULT TYPES 2



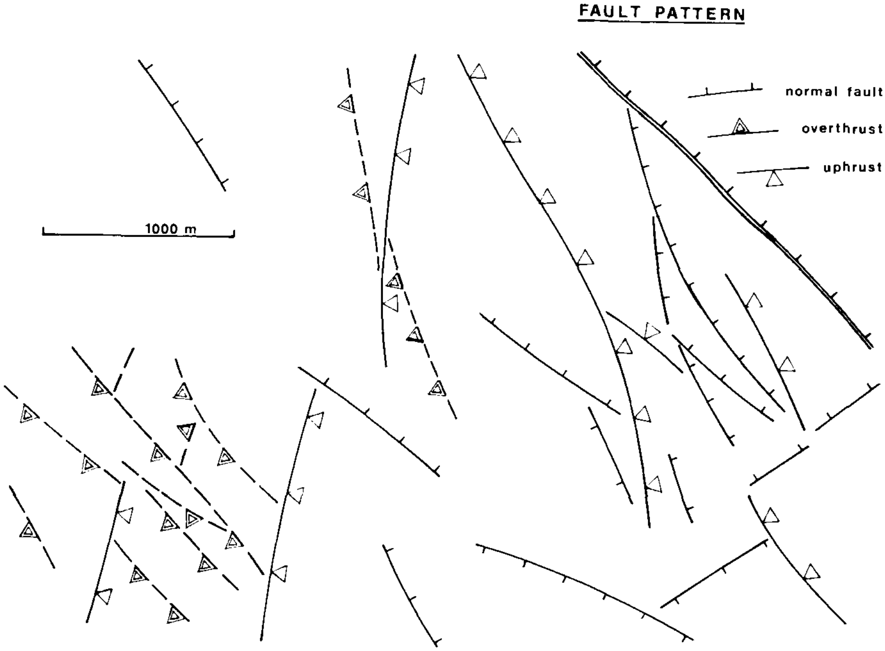
Although there are many examples of faults that can without difficulties be assigned to one of the three basic categories discussed on the preceding page, there are also numerous others which cannot be so fitted-in.

A quite common type is the steep reverse fault or upthrust – as distinct from the low-angle overthrust – which is quite common in certain structural styles, especially the compressional block style. Presumably such faults could be formed in virgin – i.e. not previously fractured – rock material as an effect of a stress system, the axes of which would not be vertical and horizontal.

Another possible explanation would appear to be that the formations in an area have been fractured in a previous phase of tectonic activity and that a later phase causes movements along pre-existing facture planes which lead to the geometry of an upthrust fault.

The majority of the fault types previously discussed is of the dip-slip type, i.e. the movement of the two fault blocks along the fault plane is in the direction of maximum dip of that plane; in other words again, the two blocks move vertically with respect to each other. In the case of the transcurrent fault, however, the movement is horizontal along the – theoretically – vertical fault planes.

There are also cases, however, and they may be more frequent than people are inclined to think, where the movement is neither vertical nor horizontal, but in some direction between the two. This is called oblique slip and can occur in both the normal fault and the reverse fault geometry. But it is often difficult to establish with certainty whether or not there has been a horizontal component in the movement. This may be typical of the wrench fault structural style, where the faults in section view have the characterisitics of upthrusts, but are believed to have a marked transcurrent component.



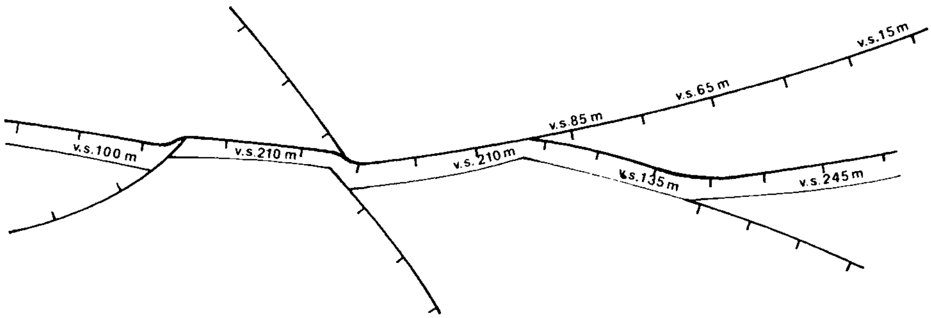
Since tectonic forces are in principle of a regional nature, the stress fields that they set up tend to be rather uniform over sizeable areas, certainly of the dimensions of the normal oilfield. As a result the faults which may develop out of the shear planes tend to occur in sets, the members of which are essentially parallel. This tendency is a helpful element in the conceptual model that the geologist may form of the fault pattern.

The ideal conditions for studying fault patterns are found in mines, where the underground workings form a three-dimensional network of observation lines and planes which permits unequivocal and objective definition of faults. This is in marked contrast to oilfields where fault patterns, as mapped, are largely the product of subjective interpretation.

The figure above was derived from a colliery map. It shows several systems of parallel faults, which originated during several orogenetic periods. The overthrusts are the oldest faults and show a clear parallel pattern, in a NW-SE direction. Some of the upthrusts are nicely arranged NNE-SSW. The normal faults are less systematic, although NW-SE directions predominate; it is possible that more than one set exists.

Nevertheless, the faults, although roughly parallel, do show appreciable variations within a set. One of the causes for this is probably the inhomogeneity of the rock material which in turn causes local deviations in the stress patterns and thus in the geometry of the shear plane sets.

BENT FAULT



An experienced geologist once stated: 'Mother Nature never created a curved fault'. He was no doubt aware that this was an unfounded generalization: overthrusts in thrustbelts and the faults in rollover-and-growth-fault environments are certainly curved, not only in section view but quite often in map view as well.

Nevertheless, the statement was not as faulty as it might appear. For instance, the diagram shows a case of a major fault with over 100 m of throw, which in regional view does appear to be lightly curved. But a detailed analysis, feasible in the workings of a coal mine, showed that in reality the fault is made up of segments which in themselves are essentially straight, but together form the curved track. It is also of interest to note that the segments differ appreciably in throw and in dip angle (as shown by the width of the fault gap).

The very complete data from the mine surveys further reveal that the segmentation of the main fault is obviously related to the existence of minor faults which branch off from the main fault. At least for one of those it could be shown that the throw of the branch fault decreases markedly away from the branching-off point.

It is known that the area has been subjected to several orogenetic periods and that the extensional tendency which gave rise to the throw of the main fault was the youngest major phase of tectonic activity. It seems likely therefore that the stresses set up during this latest phase 'made use of' the pre-existing systems of fracture planes to form the major fault (and several other major and roughly parallel faults). Also, these movements probably affected the already existing fractures, causing the variation in throw along the minor faults.

There is reason to believe that this condition is very general in many tectonic environments, especially those where the rocks subjected to the orogenetic forces were well-consolidated. It seems likely that once a stress field has set up its appropriate system of shear planes, the rocks will not react as virgin material to the stresses of a later tectonic phase. Thus an area which has been affected by a series of tectonic events, each with its own stress system in its own orientation, is probably set through by many different fracture systems. Later stress systems are likely to find a pre-existing system of fractures that fits its directional requirements, as shown in the example on the preceding page.

If a major crustal block is subjected to horizontal (tangential) tectonic forces, two conjugate sets of shear planes are set up, the two sets enclosing an angle of some 60 degrees. (ref. p. 97). It is often attempted in geological studies to derive from the orientation of apparent sets of conjugate faults the direction of the deforming forces. Apart from the difficulties in recognizing such conjugate sets with any reliability, it would seem that the conclusion on the direction of the stress system is permissible only if the rock material had not had its cohesion broken previously by an earlier stress system.

A similar reasoning may be valid in the case of a later fault intersecting a preceding one, such as is shown in the figure on p. 96. Geometrically the construction shown is correct. One might wonder, however, if mechanically the situation would not be more complex than is assumed in these constructions. Unless the older fault has been completely healed over, perhaps by mineralization, it seems possible that the block of rock material would not have reacted so as to produce the simple, clear-cut fault intersection.

In fact, detailed observations on faults in nature suggest that the actual conditions at the lines of intersection of two faults are complicated by the existence of swarms of shear planes with small movements, which may be regarded as minute subsidiary faults.

It is one of the considerable difficulties of the production geologist's life that, although he has to work with conceptual models in which parallel faults, conjugate fault sets and intersecting faults are essential elements, he must also live with the suspicion that the actual situations are probably not as simple as the theoretical considerations would suggest.

C.12 REVIEW

The structural work done in the oilfield aims at producing the best possible picture of the three-dimensional geometry of the complex of more or less deformed rocks through which the wells of the field have been drilled.

In most cases this means that the entire complex has to be analyzed and conscientiously mapped in detail. No part of the complex must be left unexamined, if any information about its structure is available, because complications may be found which could be of importance for the unravelling and description of the entire complex.

This thorough and comprehensive operation is, however, not an aim in itself. It is carried out only to lead up to the ultimate objective: the best possible and most reliable description of the shape of the reservoir or reservoirs in the field, because that is where the interest of the industry lies.

At the very least a contour map showing as accurately as possible the depth of the top of each reservoir zone is required for use in such operational matters as selecting well locations or targets, estimating reserves, etc. If the tectonic situation is at all complex, it is likely that other maps will be needed: maps on the tops of reservoir subzones; on the base of the reservoir zone, if its thickness is variable; perhaps isochore maps of such units; all the maps of course showing the positions of faults which might act as barriers within the reservoir. It is up to the production geologist to decide which documents to prepare in view of the peculiarities of the case he is dealing with. But also he must take into account the needs of those of his colleagues in the organization who will have to use his drawings as a basis for their own work.

In summary, the objective of the structural work is to produce the best possible picture of the *external geometry* of the reservoir(s). The next chapter will deal with the analysis and description of the internal structure of the reservoir.

Chapter D

RESERVOIR GEOLOGY

D.1 PRINCIPLES

The production geologist is not interested in rocks for their own sake, but because they may contain open spaces (= voids = pores). This is so because the oil industry depends for its very existence on the presence of such voids in some rocks, for two reasons:

(a) the oil (gas) lies stored in the voids;

(b) the oil (gas) moves through the voids towards the wells during production.

Two measurable physical properties of the rocks are related to these two aspects:

– *porosity* is an expression of the volume of void space in the rocks and thus is related to the volume of oil or gas which can be recovered from the reservoirs.

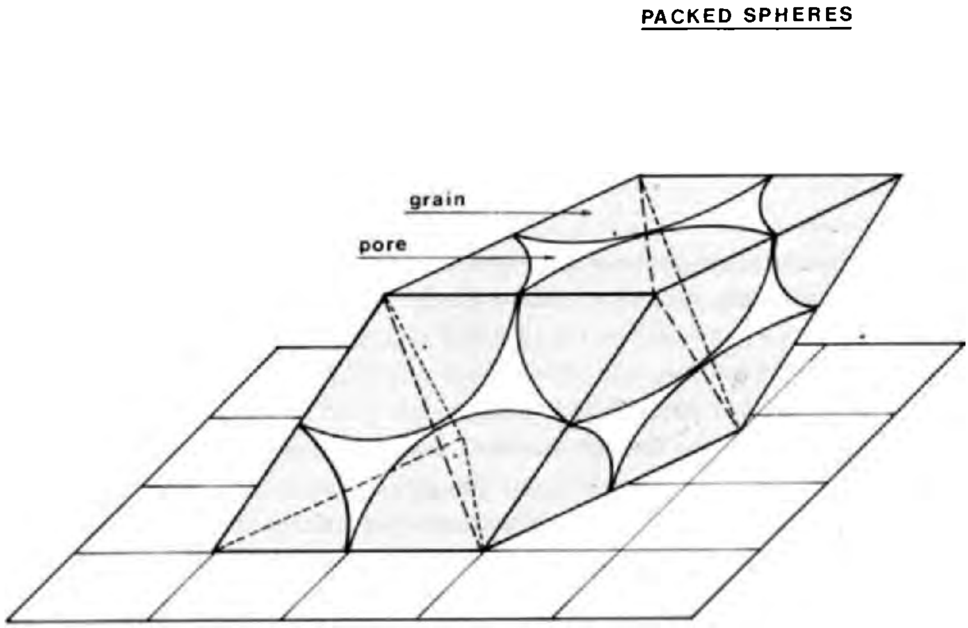
– *permeability* describes the relative ease with which fluids can move through the reservoir and is therefore a factor in determining the productivity of the wells in a field.

The magnitude of these two parameters for any particular rock depends on the composition and texture of the rock. These in turn are determined by the conditions in which the rock was deposited and on the later history of the rock. Both these aspects – sedimentation and diagenesis – are subject matter for sedimentology and, therefore, are dealt with in the geological studies of an oilfield.

Over the recent decades the science of sedimentology has developed rapidly and thoroughly. Sedimentological studies of reservoir rocks are to a large extent the province of specialists in sediment description. But the production geologist has to understand their results and to build these into his general description and understanding of the reservoirs.

The structural studies, dealt with in Chapter C, described the external geometry of the reservoir. It will be clear from the foregoing that the reservoir geological studies lead to the description of the internal structure.

D.2 POROSITY

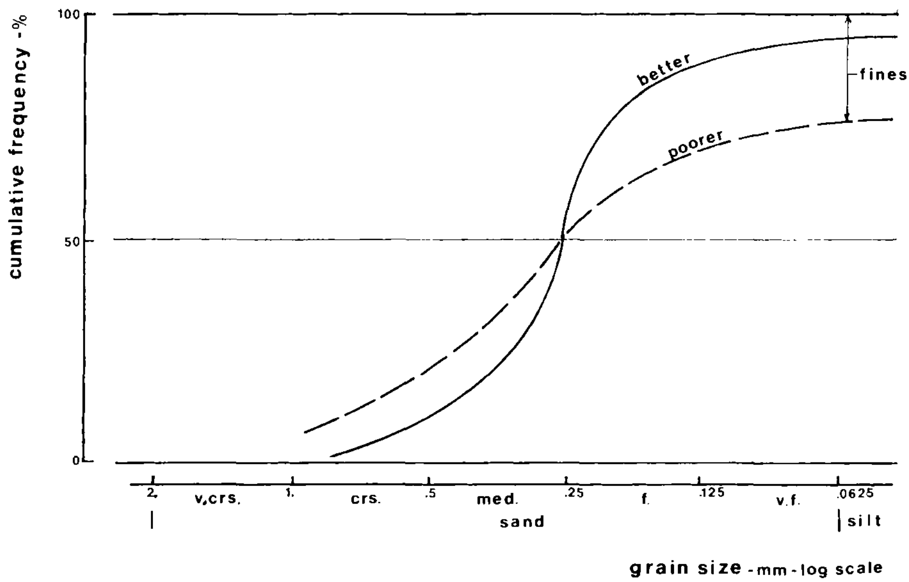


Porosity is defined as the fraction (or percentage) of pore space in the total bulk volume of the rock.

If the grains of a rock were all spherical, all of equal size and packed as closely as possible, the porosity could be calculated simply. The spheres are arranged in a tetrahedral configuration and the illustration above represents the unit cell: an oblique parallelepiped with the centres of eight spherical grains at the corner points. The volume of grain inside this cell equals one complete sphere and the remaining pore space amounts to 0.26 of the total volume of the cell. In other words, the porosity is 26%.

It is important to note that the geometrical arrangement, and therefore the porosity fraction, is independent of the size of the grains: the radius of the grains does not appear in the final formula. Strictly speaking, this statement applies only to the packing of equal spheres, but it may be generalized to say that porosity is not strictly dependent on the dominant size of the grains in the rock. If the grains are well-rounded and all more or less of the same size, the porosity would be in the neighbourhood of the 'ideal' 26%. But because sand grains are not necessarily well-rounded and not necessarily packed as closely as possible, both higher and lower values for porosity are not uncommon in practice.

SORTING & POROSITY



Porosity of a rock is affected appreciably by the sorting of the grains. If the grains are not all more or less of the same size, in other words if the sorting is poor, the finer grains are likely to lodge in the interstices between the larger grains and thus to reduce the pore volume and the porosity.

As discussed above, the porosity is not clearly related to the dominant grain size of the rock. But there is a relation between porosity and sorting of the grains of the rock. Attempts have been made to quantify this relationship, but it is not generally possible to calculate accurate porosity values from the measured grain-size distribution.

Porosity can be measured directly, if suitable samples of the rock can be taken for analysis, i.e. if the rock is sufficiently consolidated to obtain coherent and nondeformed samples. The sample is weighed, first dry and then saturated with a fluid of known density; the porosity is computed from the weight difference. Also, wireline logs can be taken in the wells which measure rock properties related to porosity: density, sonic velocity, neutron response. Logging companies will usually provide a porosity log computed from these measured logs.

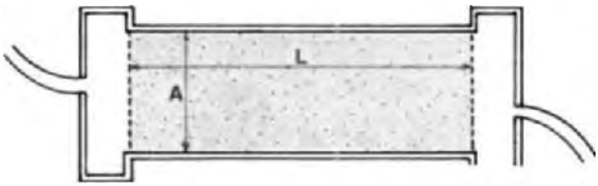
A further complication in the relation of porosity to grain size appears in very fine-grained rocks. The platy minerals, which are the major component of clays, exist in the form of minute flakes, on the surface of which water is adhered. This water tends to keep the flakes apart and thus leads to rocks which have a high nominal porosity, possibly in the neighbourhood of 40%, or even 50%. These pores, however, are so small that they can contribute little or nothing to production of hydrocarbons, as will be discussed further in the next section. The pores that do contribute to oil production therefore must be larger; this part of the total porosity of the rock is referred to, in consequence, as effective porosity.

Although these theoretical considerations and complicating conditions have to be kept in mind when dealing with reservoir rocks and their porosity, it is useful also to remember a set of porosity values which occur commonly in oilfield practice. For rocks which are known to be hydrocarbon-bearing and which have proved to be able to release these hydrocarbons for production through the wells, the value of effective porosity varies usually within a fairly narrow range:

less than 10%	: poor, productivity doubtful
10 – 15%	: fair
15 – 25%	: good, the most common range in productive reservoirs
over 25%	: excellent, but rare.

D.3 PERMEABILITY

DARCY'S LAW



Darcy's Law: $Q = k \times \frac{A}{L} \times \frac{\Delta P}{\mu}$

where Q = flow rate
A = cross-sectional area
L = length
ΔP = pressure gradient
μ = fluid viscosity
k = permeability

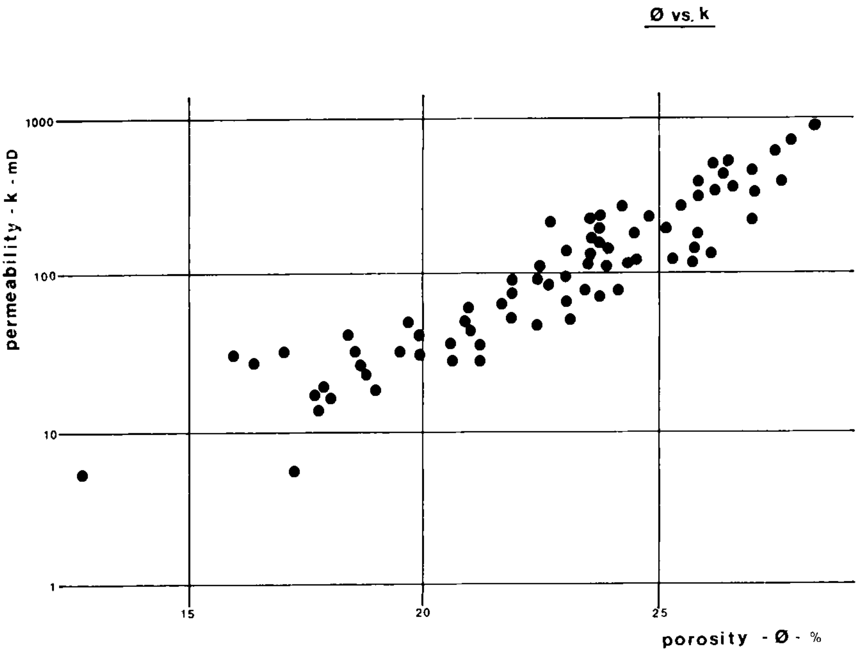
Permeability is a measure of the resistance with which a rock opposes the movement of fluid through its pores.

Obviously, the larger the pores, the easier the fluid will flow through them, i.e. the higher the permeability of the rock. By and large, larger pores occur in rocks with larger grains and, consequently, permeability is related to grain size. But the relationship is complicated by such effects as: the shape of the pores; the size of the 'pore throats' at the grain contacts; the presence of fine material or secondary mineral growth partially blocking the fluid movement through the pores; etc.

Permeability is measured by actually flowing a fluid (or a gas) through a sample of the rock. It will be obvious that the quality of the sample must be suitable and that, for instance, poorly consolidated rocks will present difficulties. The measuring procedure in in fact an experimental version of the Law of Darcy, which describes the flow of fluids through porous media: permeability is computed as the factor k in Darcy's formula from the measured values of the other parameters.

Permeability is expressed in darcies, but as few reservoir rocks have permeabilities of more than a fraction of a darcy, the more common unit is the millidarcy (= 0.001 of a darcy).

Apart from measurements on samples, a permeability value can be determined from pressure build-up surveys in a well. The resulting permeability value is a kind of bulk permeability, representing the permeability of all the rocks that are open to production in the well. These measurements are useful in calculations of well productivity, reservoir depletion, etc.



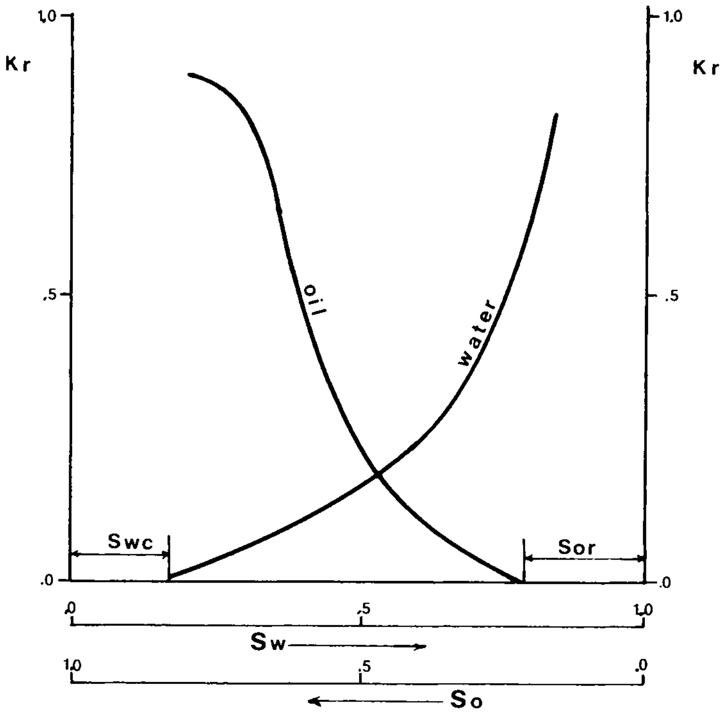
As both porosity and permeability are, albeit loosely, related to grain size, there should be a relationship between the two properties for a group of rocks. The graph shows the relation for a selected group of samples from rocks of very similar depositional origin; in consequence of this selection, the relation is exceptionally good in this instance. Nevertheless, the permeability values can still vary by several hundreds of millidarcies for the same value of porosity. The relation is, therefore, in most cases not clear enough to permit a useful estimate of permeability to be made from known porosity figures. For some, especially suitable, rocks it may be possible to arrive at a useful estimate by taking into account also the grain size distribution and log parameters.

The permeability of reservoir rocks is a most important element in controlling the productivity of the wells. For oil production the following appreciations may be useful:

10 mD	– poor
100 mD	– fair to good
1000 mD (= 1.D)	– excellent

Permeabilites of more than 1 Darcy do occur but are rare. For gas production somewhat smaller permeabilities than 10 mD may still be acceptable in practice.

RELATIVE PERMEABILITY



An important parameter in reservoir engineering calculations is the relative permeability or, in more homely terms, the way in which oil and water share the available permeability of the reservoir rock when each of the two fluids occupies part of the pore space.

As the graph shows: the higher the oil saturation (*So*), the higher the permeability to oil; in other words, the more oil is contained in the pores, the easier the oil will move through the pores. Conversely, the more water is contained in the pores (*Sw*), the less easily the oil will move.

For oil production it is also very important that both the oil curve and the water curve approach the zero line for appreciable saturations of oil, respectively water. This means that as oil enters the pores, as happens during the accumulation process, it can never replace all the water that was originally present in them: there remains an 'irreducible water content, *Swc*', also known as the connate water saturation. Similarly, if water enters the pores to replace oil, which has moved to the producing wells, it cannot drive out all the oil: a 'residual oil saturation, *Sor*' remains. Related phenomena will be discussed in Section F.2.

D.4 PORE SPACE AND SEDIMENTOLOGY

In the early years of the oil industry, when a well was drilled, it was largely a matter of surprise what kind of reservoir it would encounter: good or poor. If the pore space of the rock was well developed, the well would turn out to be a good producer (assuming no other disturbing influences were active); if, however, porosity and permeability were poor, the well would produce little, or even be entirely 'tight'. (So called because the reservoir at that spot was poorly porous or 'tight'). The causes why one or the other alternative condition was encountered could rarely be understood in those days.

In recent decades this condition has been improved upon, because much research has been done on the properties of sediments on the scale of the oilfield, i.e. on the sedimentary conditions in bodies with dimensions in the order of a few hundreds of metres. (It is perhaps not entirely unfair to say that, previously, sedimentologists had been working on a scale of either kilometres or centimetres.) This research has provided us with improved understanding of the geometrical, spatial distribution of different rock types and of the relationships of these bodies of different rock types to each other; this improved understanding is largely based on the study of the genesis of these sediment bodies.

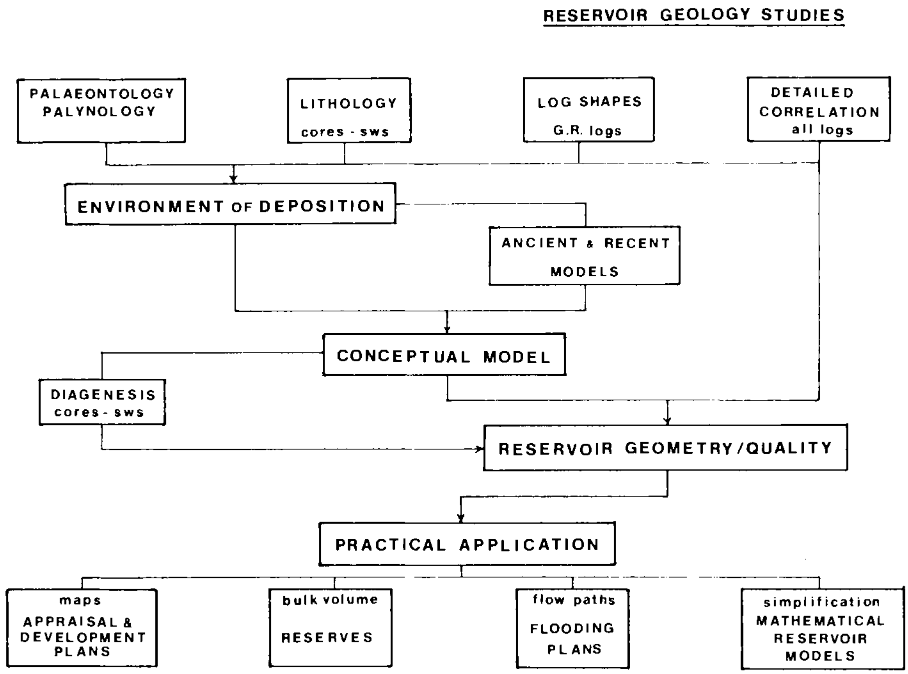
The increased knowledge of the geometry of reservoir rock bodies improves our capability to predict whether a well is likely to encounter good or poor reservoir rock; or rather how to avoid drilling wells in locations where poor reservoir rock would probably be encountered.

The more refined knowledge also helps in refining the estimation of reservoir rock volumes and hence of the reserves present in the reservoirs.

A factor which has helped in stimulating research into sedimentological phenomena is the more common application of secondary or supplemental recovery methods. Proper application of these methods requires as good as possible an understanding of the flow of fluids through the reservoirs, which in turn, of course, depends on the variations of permeability through the bodies of reservoir rock. These fluid flow processes are often studied by means of numerical, computerized models and the sedimentological studies help to refine the reservoir descriptions on which the models are based (cf. Section H.4).

Also, thanks to the increased knowledge of sediment geometry, it is often possible to draw a fairly accurate picture of the permeability variations for the purpose of mapping the 'flow paths' through which the fluids will preferentially move.

The purpose of the sedimentological studies of the reservoirs is thus to portray as accurately as possible – to draw the 'most likely' picture – the internal structure of the reservoir. Such sedimentological studies tend to be developed more or less along the same course, as shown in the following flow diagram.



The first step in the study of a reservoir rock complex is to define, as well as possible, the environment in which the rocks were deposited. If data from contained fossils – fauna or flora – are available these will be of great help, but in practice this may often not be the case. The main source of decisive information then is the detailed study of the lithology of the rocks in the reservoir. Ditch samples and sidewall samples are useful, but experience has shown that conclusive results can rarely be achieved without a good set of cores.

It is therefore common practice to obtain in any oilfield at least one set of cores covering the entire thickness of the reservoir zone. In order to ensure that the rocks of interest are indeed recovered, it is usually best not to core in the first well in the field, but to wait until a later well, when the section to be cored can be accurately selected and its structural position can be predicted reliably.

The examination of cores for sedimentological purposes has developed into a discipline by itself. Usually the cores are sliced lengthwise to expose a flat and clean surface, suitable for microscopic examination. Sedimentary features are recognized and recorded: cross-bedding, wavy bedding, burrows and other faunal disturbances, sliding phenomena, etc., which are useful indicators of genetic type.

Also, samples are drilled out of the core at regular intervals of a few decimetres – and additionaly at points of special interest – for analysis of grain size, porosity, permeability, faunal and floral content, etc. The examination of cores and other rock samples may be done by the production geologist himself, but is more likely to be entrusted to specialists within or outside his own organization.

Another source of environmental indicators is found in the shape of log curves. These are especially useful in the study of sandy sediments and examples will be described in the following sections.

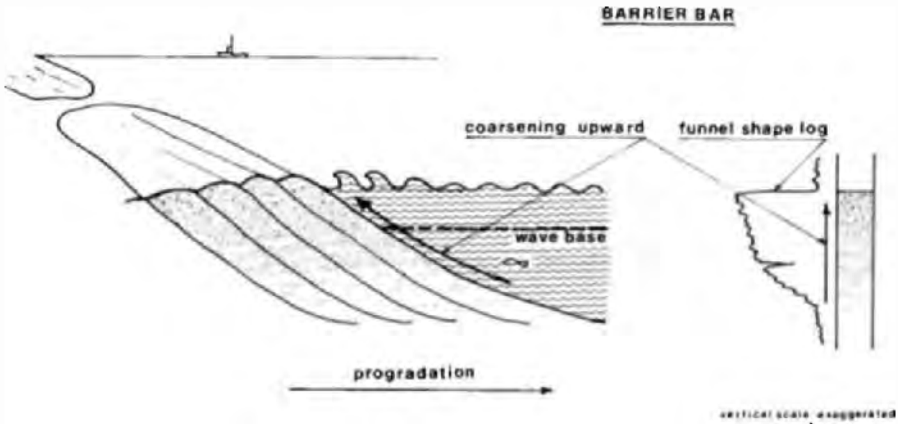
A major part of the study is the very detailed correlation of the reservoir zone in all the wells in the field. The ultimate objective of this part of the work is to unravel the sediment complex into its smallest recognizable constituent parts, known as 'genetic sedimentary units'. Such units should be the product of one coherent depositional process and, in consequence, fairly homogeneous and well-defined of outline. They are, in other words, the building stones of the reservoir complex and, therefore, together form the total volume in which the hydrocarbon reserves are contained and also the complex of flow channels through which they can move.

Just as in the structural work, the geologist requires a conceptual model of the probable geometry of his reservoir complex. Such conceptual models can be derived from the results of the research. This research has studied – and continues to study – the mechanics of sediment deposition as it goes on at the present time; these studies also include the characteristics of the resulting sediment bodies: geometry and sedimentary features. The results can be used as models of sedimentary complexes as they occur in the Recent. In order to check these findings and to extend the collection of models, rock complexes of specific depositional origin have been studied in outcrops of formations from earlier geological periods, preferably where large structures, in the order of hundreds of metres, are exposed. These investigations provide Ancient models for the use of the geologist.

When the probable environment of deposition of a reservoir complex has been tentatively established, these models are used for comparison purposes. First, to check on the preliminary determination of the environment of deposition, to see if it is sufficiently reliable. Next, to provide the model of the geometry which may be expected, and of the variations of the properties of the reservoir rock. Working with this conceptual model in mind, the geologist then has to produce the graphic representation of the reservoir characteristics; what type of graphic means he will use depends partly on the type of sediments he is dealing with and partly, perhaps most importantly, on the purpose for which his work is intended.

The following sections will attempt to illustrate some common sedimentary models and the various types of diagrams used in their analysis and representation for practical application.

D.5 PORE SPACE IN SANDS/SANDSTONES

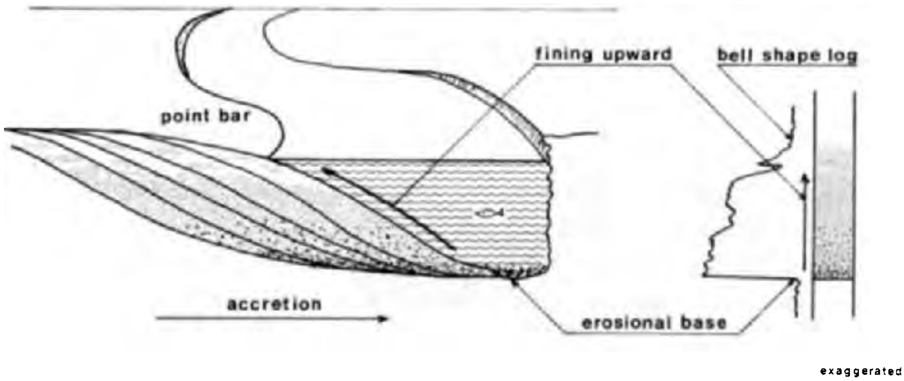


In principle, the pore space development in sandy sediments is better as the grain size is larger and the content of fine interstitial matter is smaller. Sediments with these characteristics are commonly formed in so-called high-energy environments, i.e. those environments where currents and waves play an important part. And as such environments are most common in shallow water, a large proportion of all sandy reservoir rocks have originated in deltaic formations.

A typical deltaic deposit, in wich many and good-quality reservoirs have been formed, is the barrier bar. In many parts of the present world, coasts are characterized by the occurrence of barrier islands. Thanks to the transport of sedimentary material into the area, the delta grows seaward and consequently the islands also grow seaward by the process known as beach accretion or beach progradation.

The uppermost zone of these barrier bar deposits, say down to a depth of about 20 m, is exposed to the action of waves. The water movements set up by the waves have the effect of winnowing out the fine material from the sediment; these fines are then removed by currents to deeper and quieter water, farther offshore. The resulting sediment body is fine at the bottom and becomes coarser in the higher levels. This 'coarsening upward' is reflected in the shape of a lithology log – usually the Gamma Ray log – as a so-called 'funnel shape'.

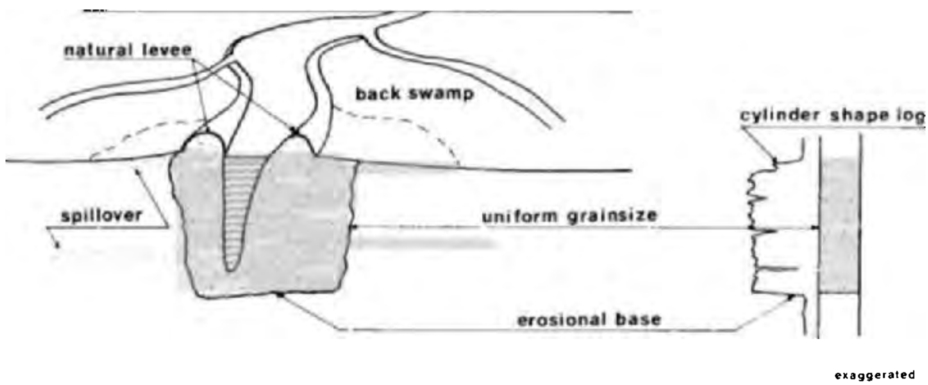
MEANDERING CHANNEL



Another typical feature of deltaic deposition are the meandering streams, which occur in the 'upper deltaic plain' (so, strictly speaking, in the terrestrial zone, comp. p. 116). The figure sketches a bend in such a meandering river. On the outside of the bend the stream undercuts the bank progressively, gradually moving the bend farther outward. On the inside of the loop sedimentary material, carried from upstream, is deposited in the form of a point bar. The coarsest material is left in the deepest part of the channel, where the current is strongest, and the finer material is sedimented more towards the inner bank. Thus the point bar also gradually grows outward, with the coarsest sands – or gravels – at the bottom and the fine clayey material at the top. This 'fining upward' sequence is reflected in the gamma ray log as a 'bell shape' log.

The geometry of these river deposits can be quite variable. First, because the size of the depositing stream can vary from a minor creek to a mighty river and the point bar bodies vary in size accordingly. Moreover, the meandering streams are by their nature highly mobile and tend to move back and forth over the country. In this process it is common that a previously deposited point bar is cut into again by the stream and perhaps partly removed, the newly formed bar taking its place. In this way quite wide belts of river deposits can be formed, known as meander belts. In the subsurface it will generally not be possible to identify individual point bars, but the deposits of a meander belt can create the possibility of widespread reservoir sands, characterized by the bell shape logs.

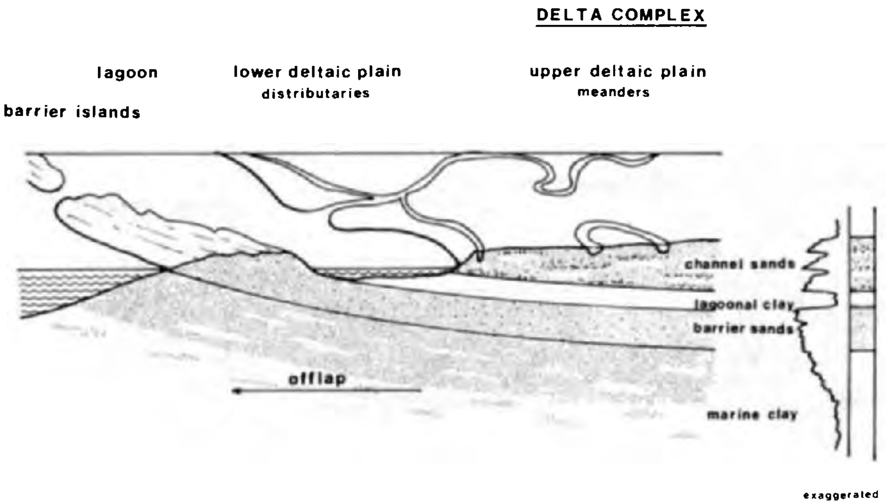
DISTRIBUTARY CHANNEL



A different type of channel commonly occurs lower on the delta plain, i.e. closer to the seashore. These channels are mostly non-meandering and frequently bifurcate to form the intricate channel patterns typical of the lower delta.

Apart from the current in the channel, caused by the run-off of the river water towards the sea, these channels are often under tidal influence (tidal channels, estuarine channels), which sets up ebb and flow in the channel. Together these currents produce a process of erosion and deposition in which the channel moves back and forth through a more or less ribbon-shaped sediment body (prismatic in the exaggerated figure above). These sediments are frequently reworked in the process, with the result that the grain size does not vary greatly from bottom to top of the channel sand. This, in turn, is reflected in a log shape that is fairly uniform from top to bottom and is referred to as a 'cylinder shape' log. Naturally there is still a tendency for the fine material to be concentrated in the upper part of the sediment unit and the logs often still show vestiges of a bell shape. Because currents in the channels are strong and transient, the sediments often show irregular and disturbed current bedding and are mostly poorly sorted.

As a result of variable water supplies, the levels of the channel streams often rise above the river banks and water overflows into the back swamp area. The coarsest part of the sediment load in this water drops out close to the channel and builds up the typical natural levees of the lower delta plain. Finer sandy material can find its way farther from the stream channel and be deposited as spillover sands. In some cases these levee and spillover deposits are recognizable in subsurface formations.



Because several major oil-producing areas produce from sands of deltaic origin, the figure represents, schematically and simplified, the complete delta complex as it occurs at several places in the present world. More detailed and comprehensive – and, no doubt, more correct – descriptions can be found in many textbooks.

The log attempts to sketch the way in which a full delta cycle of deposition can sometimes be recognized in well logs. At bottom are the marine clays, pure and generally carrying an open marine fauna. Upwards, more and more sandy intercalations are encountered and the log correspondingly shows a funnel shape. This part of the cycle usually ends with a sandy interval, generally of quite pure, well-sorted beach sands, but locally also containing sands of estuarine channel origin. The lagoonal clay – with rich, very shallow marine fauna and carbonaceous matter – is recognizable in some cases. The upper part of the cycle represents the deltaic plain and is characterized by channel sands, probably less 'clean' than the barrier sands, more often intercalated with clay beds and characterized by bell shape logs. The entire sequence is referred to as an offlap sequence.

From the simplified sketch it is possible to derive some ideas regarding the geometry of the various sand bodies originating in the deltaic environment. The barrier bar sands are usually elongated with a roughly lenticular cross section; the long axis is parallel to the coastline (at the time of deposition!). Distributary or estuarine channels tend to produce ribbon-like sands, often sharply limited at the edges, which may result in unpleasant surprises in oilfield development; their dominant direction is likely to be normal to the coastline. Sands formed by meandering streams tend to occur in more widespread sheets – sheet sands – in which individual point bars may or may not be recognizable and clay intercalations are common.

Apart from the sands produced in the deltaic environment, several other types of sands are encountered as productive reservoir sands.

Geologically, even esthetically, attractive are complexes of dune sands formed in a desert environment. Cores of such sands show considerable thicknesses (several metres) of beautifully cross-bedded sands with very straight bedding planes and very constant dip (often close to the maximum angle of repose of dry sand in air, about 27 degrees). Dipmeter evidence (comp.p. 45) shows that the prevailing wind direction was very constant during long times. Because the winds tend to be strong, the fine material is blown away and the sands are well-sorted. Locally these series of foreset beds are interrupted by more argillaceous bottom-set intercalations.

In some cases series of sands have been shown to have originated in deep sea water, as a result of turbidity currents carrying the material from the shore into the basinal marine area. The resulting formation shows the typical properties of turbidites: rapid and regular alternation of coarser and finer layers. The geometry of such complexes is of course determined by the shape of the basin, but may tend in practice to be elongated.

Related to the true deltaic deposits are series of alternating sands and clays in relatively thin layers, say a few metres per unit. Despite their small thickness these beds are remarkably constant over large areas and can therefore be correlated from well to well over long distances. The most likely mode of origin is as sheets of sediment, spread along a coastline in shallow-marine conditions by long-shore currents. Such sands are likely to be fine-grained but well-sorted and thus still attractive reservoir sands.

Thus many sands can be assigned to a specific environment of deposition, which helps considerably in establishing their physical properties and geometry. But not in all cases has the search for the most likely environment been successful and research is still going on to provide more models of, as yet, not well-established environments.

Although a fair knowledge may be available regarding the properties of a sand, as they were when it was deposited, this is not the condition in which it is usually found in the oilfield: in many, if not in most, cases diagenesis has more or less thoroughly affected the sediment material and, in consequence, altered the physical properties which are so important for oil production. These alterations may be for better or for worse, or in other words: porosity-creating or porosity-destroying.

The negative, unfavourable case is probably the more common. For practical purposes it may be assumed that in all cases pore space and pore quality deteriorate with depth: the deeper one goes the poorer the reservoir rocks, although of similar original quality, will become. This is, in the first place, the result of the increasing load of the overburden of younger sediments resting on the rocks and causing increasing compaction of the rock, by such processes as: rearrangement of grains, fracturing of grains, pressure solution at grain contacts. At the same time some of the chemically more sensitive minerals, particularly the clay minerals, may be changed into a different mineral with perhaps a different crystal shape. There are many cases where the pores in a rock are filled with, or blocked by, such authigenically formed minerals. Similarly, secondary quartz growth on sand grains will reduce the pore space.

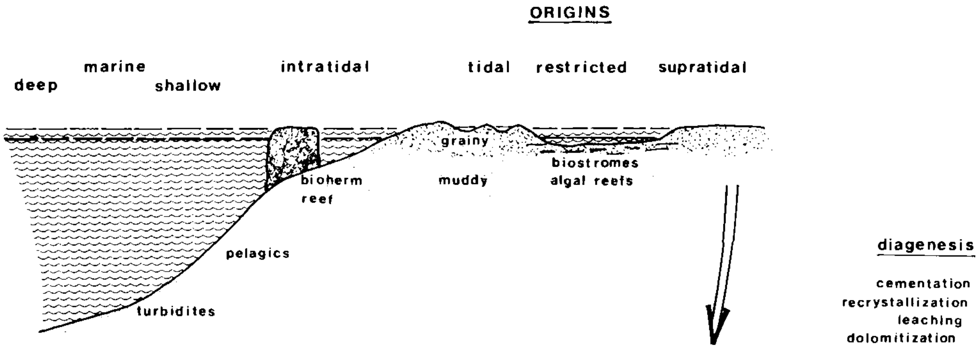
Although in general the decrease of porosity with depth proceeds fairly regularly, there are also cases where the porosity vs. depth curve is not smooth. It is possible that the formation of a particular pore-destroying mineral is tied to a specific set of pressure/temperature conditions. These conditions will be present below a certain depth and thus the reservoir rock quality can suddenly deteriorate markedly below this depth.

Also, it is not uncommon that reservoir rocks show stronger diagenetic effects in the water-saturated portion of the reservoir than in the oil-bearing portion. The presence of hydrocarbons in a rock tends to retard the chemical reactions.

The creation of pore space by diagenetic processes is perhaps less rare than one is inclined to assume: it is not always easy to recognize that such secondary porosity was not already present in the original sediment.

In general, studies of diagenetic alterations which rocks have undergone have become a specialist science and it is rare that the production geologist himself will be in a position to carry out such studies in detail. He is more likely to ensure that proper samples are taken and submit these for analysis to a specialist, who not only has the necessary know-how but also has the required sophisticated equipment at his disposal.

D.6 PORE SPACE IN CARBONATE ROCKS



The environments in which carbonate reservoir rocks may be deposited can be indicated as in the simplified sketch above. But it must be stressed immediately that the depositional control of pore space development is not nearly as strong in carbonate rocks as it is in sandy sediments. This is because diagenetic processes have a much stronger influence – negative or positive – on the structure of the rocks.

Like in sandy deposits, carbonate sediments are most likely to be coarse-grained (grainstones in the Dunham classification) in shallow water, i.e. in the tidal (intratidal) range, where the action of waves and currents removes the fine material. The grains are: faunal fragments, ooliths, faecal pellets, etc. Where the environment is of lower energy, the grains will be embedded in a fine matrix mud, to form packstones or wackestones. If there is no supply of grainy matter, the mud will settle in the form of mudstone.

Such complexes are not unlike the deltaic complexes discussed in the previous section. New elements, for which there is no clastic equivalent, are the reefs and the pelagic limestones. Reefs or bioherms are constructed of faunal material forming cohesive growths in the coastal zone; because the top of the reef can grow upwards to keep pace with relative rise of sea-level, the reefs can grow to considerable heights. In deep water, where no detrital matter from the coastal zone will reach, there may still be formed a deposit of very fine-grained faunal detritus, derived from dead pelagic fauna (coccoliths), which may later be found as chalks, often of great thickness.

Finally, carbonate turbidites also occur as reservoirs.

Several of the sediment types formed in this environmental set-up can have primary porosity, i.e. porosity which was formed during deposition. The most common are probably the grain-supported rocks with low mud content, formed in the coastal zone; in these the size and shape of the pores are determined by the size and shape of the particles. In the reef rocks the sorting of the carbonate fragments is generally very poor, large fragments, especially of corals, can enclose relatively large pores. In the pelagic deposits the grain size is small, but very uniform; hence the porosity is high but the pores are very small and the permeability therefore low, but in some cases still sufficient for production of hydrocarbons. In the turbidite sequences the coarser members may have some original effective porosity.

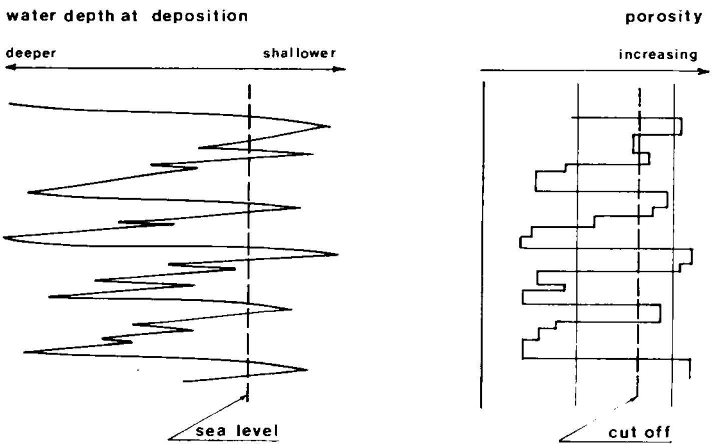
After deposition the sediments descend in the crust and are subjected to diagenetic processes. It is well-known that carbonate material is much more sensitive to these physico-chemical processes than quartzose rocks, because the carbonate minerals react very strongly to changes in the pressure/temperature environment and to the chemically active elements in the formation water. Research has shown that diagenetic processes start already when the deposits are still at the surface, especially when the material is exposed to meteoric influences in the supratidal zone. With increasing depth, the pressure increases, causing progressive compaction and pore destruction. Moreover, aquatic solutions may still circulate through the rocks to considerable depths and cause alterations. Because of the wide range of pressure/temperature conditions and of composition of the fluids, the diagenetic processes are very different in time and place; the unravelling of the diagenetic history of a specific rock is a very difficult procedure and not always successful.

The diagenetic processes can be pore-destructive. Very commonly rocks, which had good primary porosity, have their pores filled with secondary calcite growth, resulting in a severe reduction of the porosity. A similar, but more thorough, process is the recrystallization of the entire rock, which in most cases will reduce the porosity to zero.

Fortunately for the oil industry, however, diagenetic processes can also enhance porosity. Important is the process of leaching under the influence of meteoric waters, apparently starting already shortly after deposition, by exposure to the atmosphere. Not all carbonate material in the original sediment is equally sensitive to leaching; this may lead to the formation of sizeable solution voids or vugs, often by preferential dissolution of fossil fragments. If such vugs are interconnected by remanent primary pores, a very good reservoir rock may result. Less effective, but still useful, may be the process of chalkification by leaching; this produces a fine-grained, chalk-like rock with possibly effective porosity.

Very widespread, but not always fully understood, is the process of dolomitization, i.e. the replacement of part of the calcium in the limestones by magnesium. This process leads to partial or complete recrystallization of the rock and consequently to changes in the pore pattern. The best results, from an oil production viewpoint, are achieved when some 80% of the rock has been replaced by dolomite crystals of uniform size (sucrose dolomite); such rocks have porosity/permeability comparable to good sand reservoirs. If the process continues beyond the 80% stage, the resulting rock will be tight.

DEPOSITIONAL CYCLES vs POROSITY



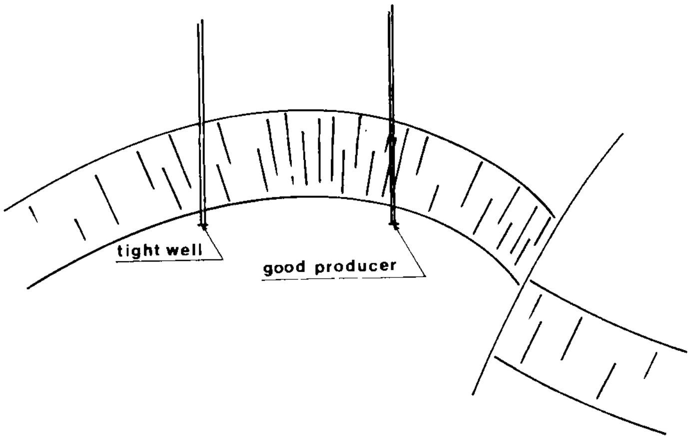
Amongst the shallow marine limestones, the ones which were deposited in the shallowest water have the best chance of becoming good reservoir rocks: exposed as they were to wave and current action, the formation of primary porosity is the most likely; the chance of exposure to meteoric influences is high; the diagenetic fluids can circulate more easily through rocks with primary pores. The deposition of such shallow-water carbonates is often cyclic: deposits of deeper and shallower water alternating, often over very thick intervals of rock. In such cyclic deposits the best pore development is likely to be found at the tops of the cycles, where the deposits are shallowest; the resulting porosity log will show a similar cyclic pattern. From experience during the production of the wells, a value of porosity can be determined below which the corresponding permeability is apparently too low to permit production of oil: the 'cut-off' value of porosity. The sketch shows that the reservoir zone is then subdivided into relatively thin productive zones, separated by tight intervals; the resulting disadvantages for production will be discussed later.

As the existence of such cycles can often be recognized from logs and samples and the pattern is relatively simple, prediction of the lateral continuity of the porous zones is not too difficult in those cases. The situation is less favourable in most other types of carbonate reservoirs. Dolomitization may be tied to specific stratigraphic levels and does not then present great problems; but conditions are not always as simple. Biohermal reefs are extremely complex structures and the study and prediction of porosity distribution is correspondingly difficult. The same applies to the very subtle variations of rock properties in the fine-grained, chalky reservoir rocks.

In practice, and especially in the early stages of field development, when well information is still scarce, the production geologist often may have to be content with the slogan: *porosity is where you find it.*

D.7 FRACTURE POROSITY

FRACTURE DISTRIBUTION



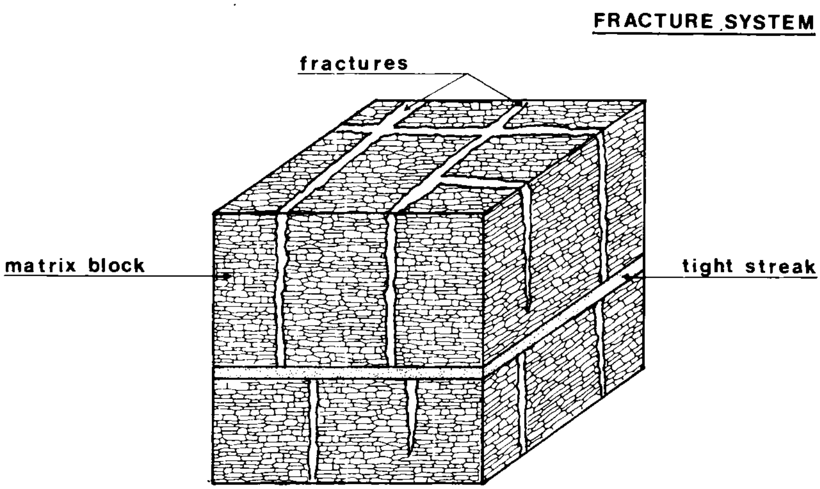
In rocks subjected to tectonic deformation, especially massive, poorly ductile rocks, fractures and joints can be formed. The oil industry has learned that in favourable conditions, such fractures can be very useful for oil production.

In practice this is especially the case in massive carbonate rocks. Partly because these have the mechanical properties which make them particularly subject to fracturing. But even more because the rock material is relatively soluble and circulating solutions can widen the fractures and thus make them the more useful as reservoirs and conducting channels for hydrocarbons.

Core evidence shows that fractures in a carbonate reservoir can be locally up to a few millimeters wide. If a well intersects such a fracture, it has a connection into the reservoir that is much larger than any pore in a permeable rock and large volumes of oil can enter the well-bore at high rates. Consequently, wells producing from fractures can be very good producers. Moreover, the productivity can often be improved by acidization: injecting acid into the fractures and thus artificially widening the flow channels.

On the other hand, the existence of large 'holes' in the bore-hole wall has a disadvantage in that the drilling mud can also relatively easily enter the formation from the well; such mud losses can be very dangerous during drilling.

Jointing is not a uniform property of a rock. Consequently, not all wells drilled into a fractured reservoir are necessarily good producers. In fact, it is likely that some wells do not encounter any fracture and turn out to be tight, non-producers. It would be of obvious interest to have an understanding of the distribution of the fractures over the productive area, but it has proved to be very difficult to find any system in such fracture distributions. One fairly general rule appears to be that the fractures are normal to the bedding planes. The dominant strike direction is probably parallel to the anticlinal axis, if any, but cross fractures also may be important. There are indications that the fracture density is related to the curvature of the rocks, i.e. to the folding intensity.

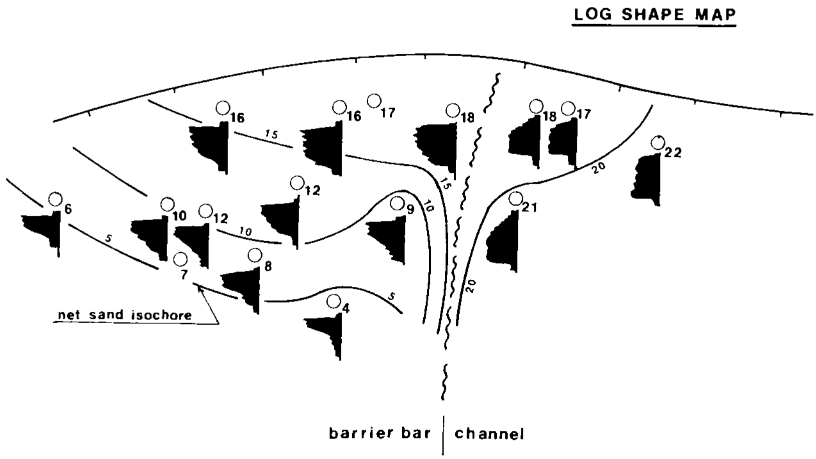


Surface geology has shown that fractures or joints tend to occur as systems of parallel planes and that two or more of such systems may intersect. If a well encounters a fracture, it is probably connected into a fracture system forming a reservoir. Such systems, however, obviously cannot be of 'infinite' extent and are probably not even continuous over the entire productive area of a reservoir. In fact, pressure histories have shown that fields often consist of more than one separate fracture reservoir.

As was stressed, fractures are likely to be best developed in massive rocks. Such rocks also may be amongst the less porous and, indeed, fields producing from fractured rocks may have their reserves contained only in the fractures, the 'matrix' rock being essentially non-porous. Experience figures suggest that fracture porosity does not exceed 2 or 3 percent of the rock bulk volume; fracture reservoirs therefore have to be large to be commercially attractive. It may also be mentioned that fractured reservoirs are not entirely confined to carbonate rocks: fracture production from igneous and metamorphic rocks is known.

There are also cases, however, where the matrix rock does have its own porosity. This means that the permeability of the rock is extremely uneven: the matrix permeability perhaps being restricted to some tens of millidarcies and the fracture systems having almost infinite permeability. The situation may be made even more complex by variations in the permeability of the matrix rock itself, for instance by the presence of tight, probably argillaceous, streaks. In such cases it will present no great problems to recover the bulk of the oil which was contained in the fracture systems. But it may be very difficult to recover, as well, the oil from the relatively low-permeability matrix blocks. During production the fracture system may be 'watered out' rapidly – i.e. all the oil in it replaced by water – and it is then a problem how to induce the oil from the matrix to enter the fractures and proceed thence to the wells.

D.8 PRESENTATION



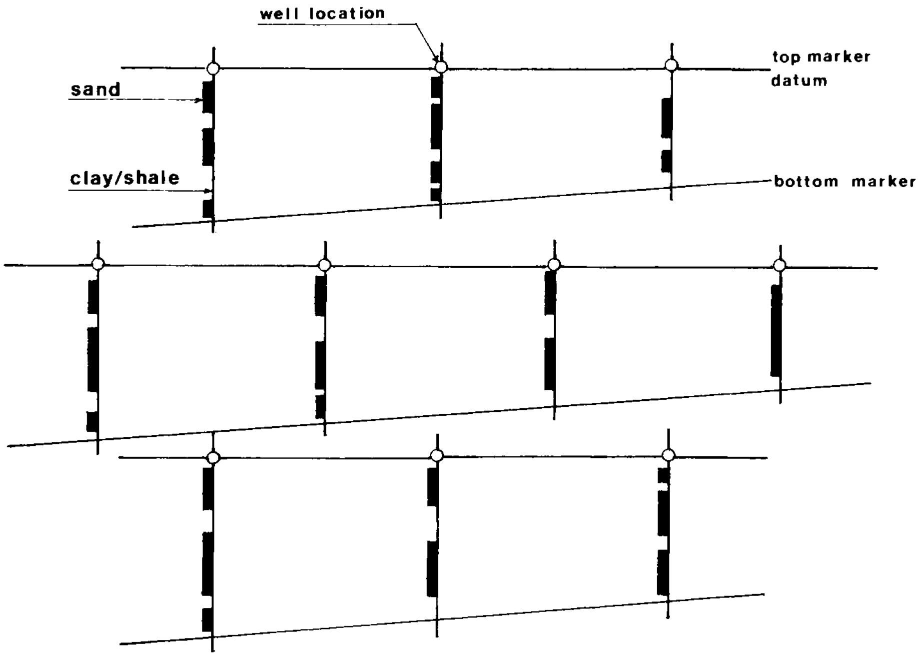
Graphic presentations used in sedimentological work can be of many different types and they serve different purposes: presentation of data, definition of environmental origin; representation of the distribution of important sediment types; etc. It depends on the type of sediment that is being studied and on the purpose for which the drawings are made, which type of presentation is selected from amongst the many available and, if necessary, a new type may have to be designed.

The figure shows a map of a sand in a field in a deltaic environment. The log shapes show that two types of sand are present in the field: the funnel shapes representing a barrier bar sand and the bell shapes a channel sand. The map is designed to show, in the first place, where these sand types occur in the reservoir. Moreover, the logs show the thickness variations of the sands over the area of interest.

One of the purposes of sediment studies is to help in the planning of field development (ref.p. 111). In this case one may expect that the production from the southernmost well will be small, because of the thin sand development, and therefore decide that drilling of further 'outstep' wells to the south is not needed. By contrast, the channel sand is thickest in the wells on the southeast limit of the present developed area and further development farther to the southeast is likely to be desirable.

Another common application is the determination of sand volume for reserve estimating. For each well the 'net sand thickness' (p. 202) for the sand unit has been determined from the logs and the resulting figures are shown on the map; from these figures net sand isochores can be constructed. This could be done by some 'automatic' method, e.g. triangulation (p. 75). But the knowledge of the nature of the sands studied, and of the likely geometry which can be derived from this knowledge, helps to draw isochores of a more realistic, and therefore more accurate, pattern.

SUMMATION

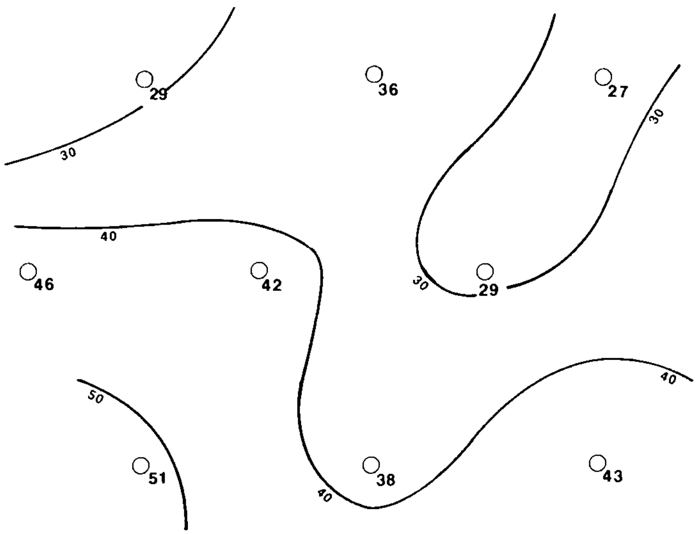


In many oilfields the reservoir complex consists of a stratigraphic interval – defined by a top and a bottom marker – within which sandy and argillaceous layers alternate. Often the logs of the layers do not show enough character to permit identification of individual sand or clay units from well to well; in other words, correlation by log shape is not possible. Also, in many cases, the distribution of the sandy layers over the interval is so irregular that correlation, on the basis of stratigraphic position with respect to the identifiable markers, is not possible either.

Such a situation is shown schematically in the figure, the sandy layers being represented by the black blocks. It will be noted that the stratigraphic sections are arranged in the 'true' positions on a field map: the lines, representing the well intervals concerned, are 'hung' from the actual well locations on the map. This is a convenient technique for the stratigraphic and sedimentological analysis of reservoir zones, because the lateral variations of the various units can be conveniently visualized. It is in fact a simplified form of the well-known fence diagram (comp.p. 133).

One of the aims of sedimentological analysis of reservoirs is the estimation of bulk volume as a step in the estimation of reserves, which will be discussed in Chapter J. In the following pages different ways of tackling the problem of determining bulk volume in such reservoir zones will be discussed.

TOTAL NET SAND MAP



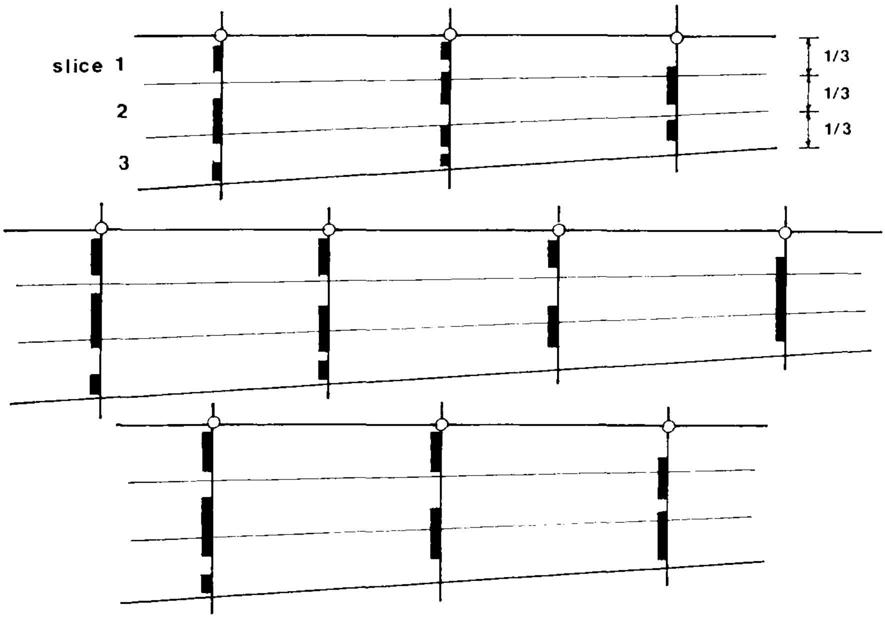
The most common tool for estimating the volume of productive rock in a situation as sketched on the preceding page is an isochore map of net productive sand.

The simplest method of measuring net sand for mapping purposes is to add up for each well the total of net sand in the stratigraphic interval in question, i.e. the total of the 'black blocks' in each well on the preceding page. The resulting figures are shown in the map above and can be understood to mean metres or feet (or some other arbitrary unit). The isochores were drawn by visual – and therefore approximate – interpolation between the well figures.

As was to be expected from the unsystematic distribution of the sand units over the stratigraphic interval – both vertically and laterally – isochores do not show any recognizable pattern. For instance, the 'low' in the northeast corner of the map might suggest a thin trend from northeast to southwest; but in the extension of this thin trend the highest net sand value on the map happens to be found (51). There is a general vague trend from lower to higher figures, going from north to south, but this is probably related to the overall thickening of the stratigraphic interval between top and bottom markers, rather than to some trend in the sand development.

Total net sand volume can of course be determined from this isochore map. But the result will probably be inaccurate, in the sense that it will deviate appreciably from what the figure is in reality. In other words, the isochore pattern is not sufficiently refined to be realistic and, in consequence, the volumetric estimate is not realistic. Modern developments in sedimentological analysis may provide the means for more sensitive and realistic methods.

SLICING

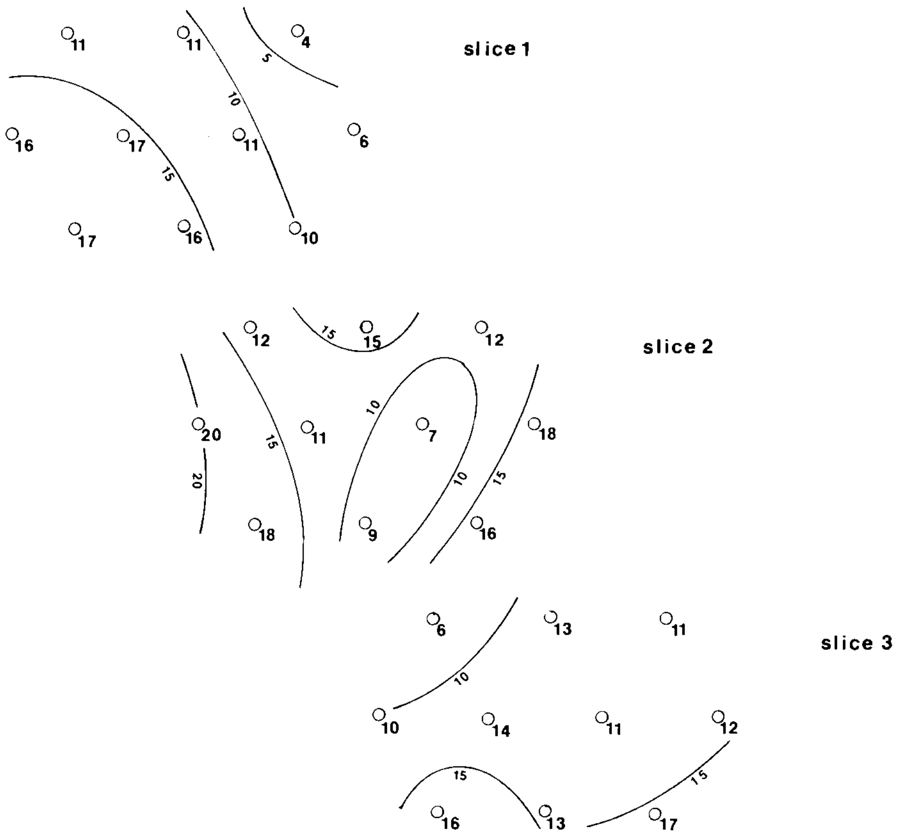


In order to improve upon the old-fashioned method of bulk sand thickness mapping, the ideal procedure would be to map separately each individual genetic unit, i.e. each rock body which was formed in one single operation of the depositional system; for instance the ribbon shape of channel sands, the more extensive elongate shape of barrier bar sands, etc. However, it was postulated so far that recognition of such units was not possible; consequently, the only way out was to add up all the genetic units in the interval together and the result is the featureless pattern of the sand isochores.

Still assuming that recognition of individual genetic units is not possible, a certain refinement can be achieved by not adding together all the units in the entire stratigraphic interval, but by splitting up this interval into arbitrary slices and mapping these separately. In the figure the interval has been subdivided into three equal slices; the net sand thickness for each slice in each well is measured and mapped (see next page).

In some cases the total thickness of the stratigraphic interval is very variable. In such cases the slice mapping will be complicated by this additional variable factor; this can be overcome to some extent by using sand percentages per slice, instead of absolute sand thickness figures.

SLICE MAPPING

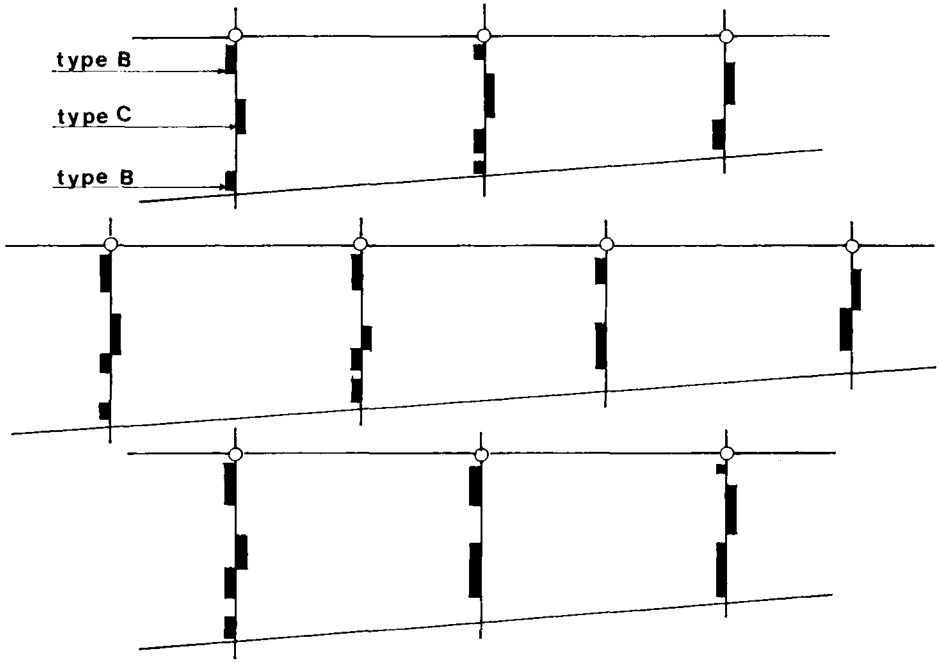


The net sand maps for each of the three slices were again made by simple visual interpolation. The resulting isochore patterns are indeed, as hoped for, more systematic than those for the total net sand thickness, shown on p. 126.

Slice 1 shows a quite regular thickness increase towards the southwest. This does not necessarily allow the conclusion that the sand in this slice belongs to one genetic unit only, nor does it define what kind of unit it could be. Nevertheless, it does indicate that the isochores are more likely to approach a realistic picture of the sand geometry and thus to lead to a more accurate estimation of sand volume.

Similarly, the middle slice shows a fairly clear pattern: from a thin stretch in the centre of the area, the thickness increases with fair regularity to both sides.

Slice 3 again shows a very regular thickness increase, this time towards the south to southeast.

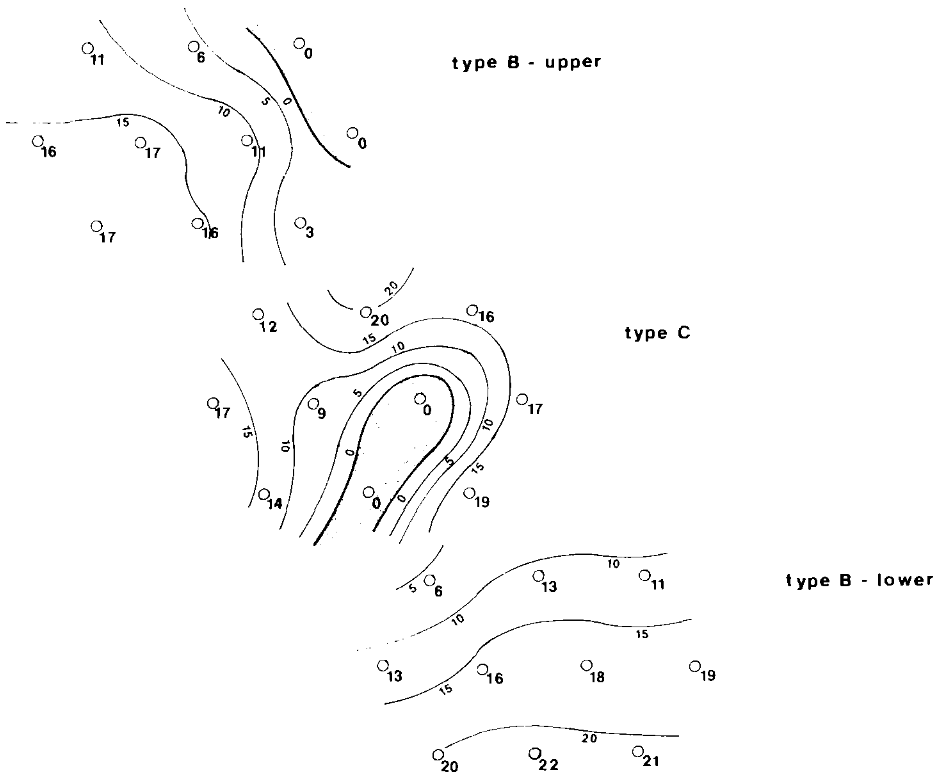


It is not impossible that where the obvious approaches – conventional correlation, log shapes – fail, more refined investigation, following a different approach, may still lead to further differentiation of sand bodies.

In the sections above, it is assumed that two sand types can be distinghuished, identified as type B and type C. Such a differentiation could perhaps have been achieved by detailed analysis of cores or sidewall samples or by comprehensive log analysis. It is not uncommon, for instance, that crossplotting of various petrophysical parameters results in the recognition of rock types, each type appearing as a separate cluster of points on the crossplots.

It will be seen that the type C intervals occur roughly in the middle of the studied interval. Type B sands are concentrated in the upper and the lowermost portions. In fact, the separation is so good, that conventional correlation could now perhaps be attempted. But difficulties would still be encountered: for instance, in the lowermost section there is clearly no direct correlation between the type C layers in the outermost wells on either side.

SAND TYPE MAPPING

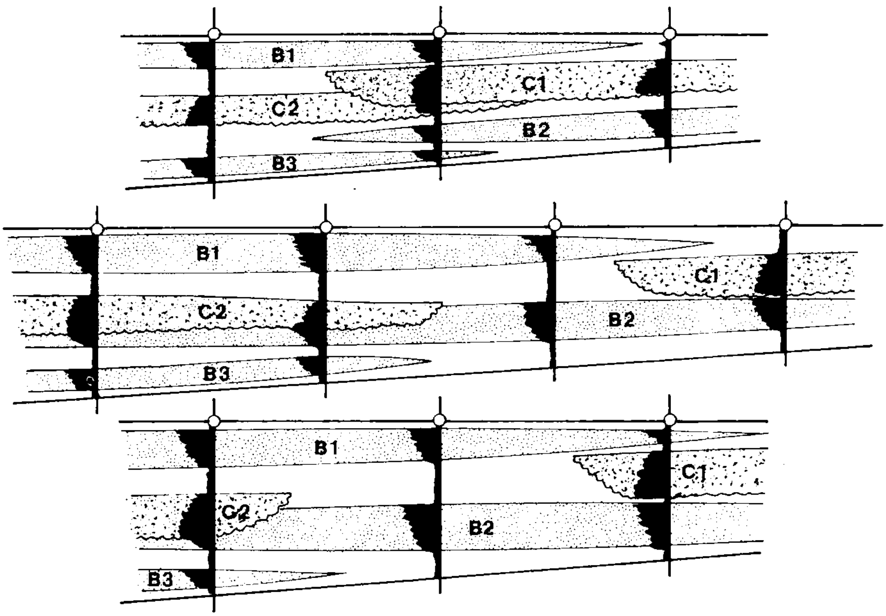


The net sand thicknesses for the two types of sand were mapped, with type B sand separated into an upper and a lower interval.

The resulting maps are not greatly different from the slice maps on p. 128, as is to be expected because the subdivision of the interval is also threefold. Nevertheless, the isochore patterns of the three maps are much more clearly expressed than those of the slice maps. Even so, they are not sufficiently characteristic to allow definition of the type of sands mapped in terms of depositional environment.

On the other hand, it does seem likely that, if the maps are used for rock volume estimates, the results will be more realistic than those achieved with the two previous map types. All this is not surprising: a new information item, the differentiation into two sand types, has been added to the operation

GENETIC UNITS

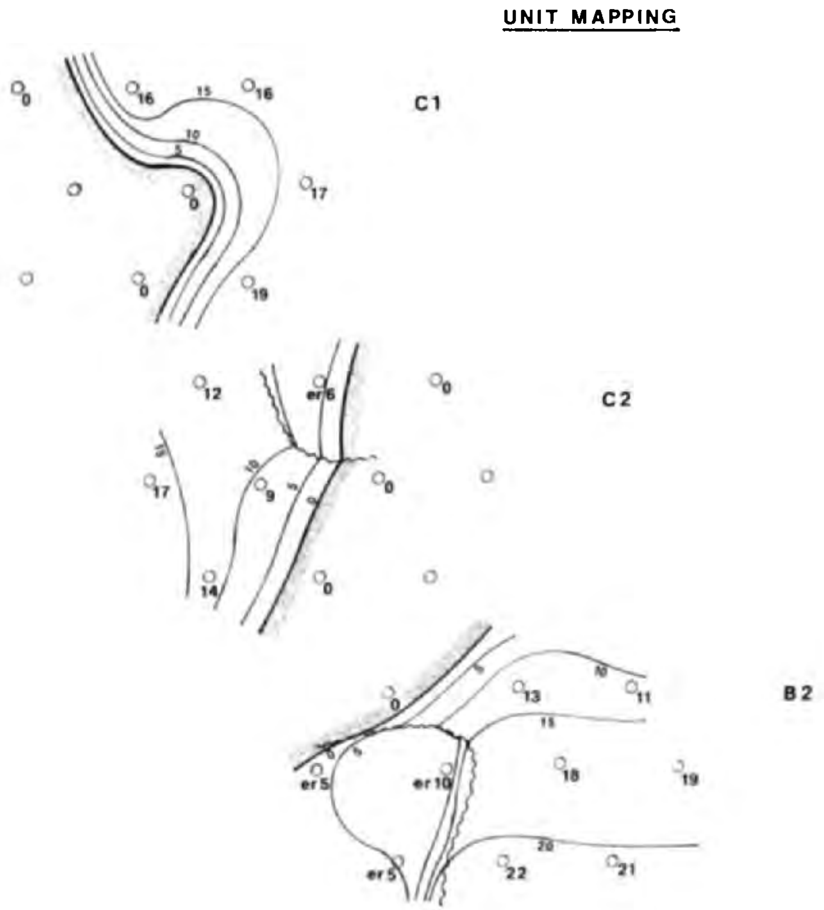


It may be useful to assume now – as a final step – that the logs *do* in fact show characteristic shapes for the various sand intervals.

For the sake of convenience, the 'traditional' funnels and bells have been introduced. Comparison with the previous set of sections will show that the funnels correspond to type B sands and the bells to type C. It may now be concluded that the type B sands are of barrier bar origin, whereas type C belongs to channel sands.

This conclusion having been drawn, it is now possible to arrive at conceptual models for the various sand units: regular wedge-shapes for the barrier sands; abrupt edges and an erosional base for the channel sands. Applying these models, a satisfactory detailed correlation of the ten wells can now be achieved as shown above; a correlation in such detail that several individual genetic units can be distinguished. The result thus is a subdivision into three barrier sand units and two channel sands. Channel sand C2 eroded down into the pre-existing barrier B2; channel sand C1 was deposited after C2 and eroded into it in the northern part of the area.

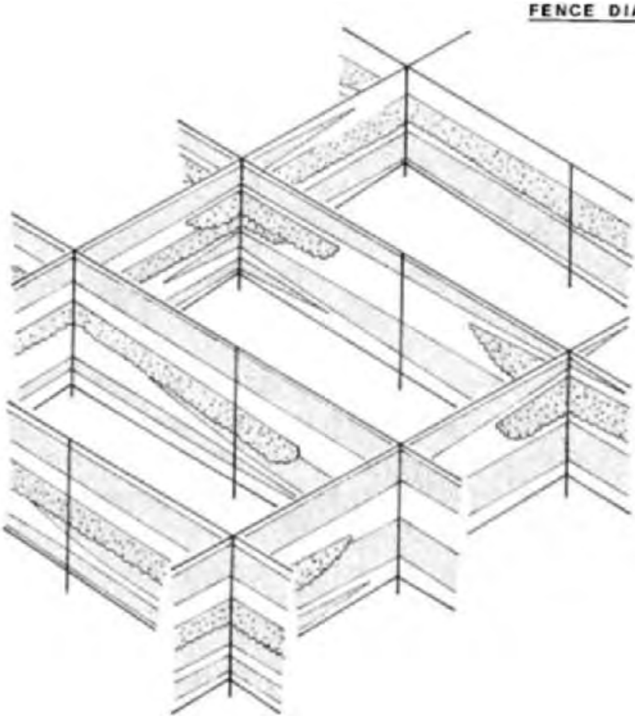
(It may be asked, in this connection, why the older sedimentary units have been given the higher numbers. In production geology it is not unusual to number any units – including markers – from top to bottom; in other words, in the order in which they are encountered in drilling rather than in the sequence in which they were deposited.)



The recognition of the five genetic units now allows the mapping of each separate unit in accordance, as far as the data allow, with the conceptual model of the geometry of the unit concerned.

Only three of the unit maps are reproduced above. An important gain in definition over the previous maps is the separation of the type C sands into two separate channel sand bodies, both showing fairly abrupt thinning at the edges and overall shapes acceptable for channel deposits. Barrier unit B2 shows the expected west – east direction, roughly at right angles to the channel trend and thus presumably parallel to the coastline at the time of deposition. It will be noted, furthermore, that the outlines of the eroded areas of sand C2 and B2 correspond to the erosional base of the channel sand C1; the construction of isochores in such situations usually requires careful consideration of the geometry.

The use of such unit maps for determining the sand volumes should lead to the most accurate results achievable for reserve estimating purposes.



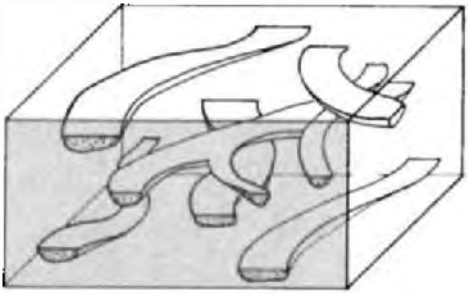
The series of sections, used to illustrate the sand distribution on the preceding pages, portray the situation in one direction only, i.e. along east – west planes. Some impression of how the sand bodies develop in other directions can be obtained from the isochore maps. However, as each map describes either one genetic unit only, or perhaps a group of units (slicing, sand type mapping), the interrelation of the different units cannot be visualized from those maps.

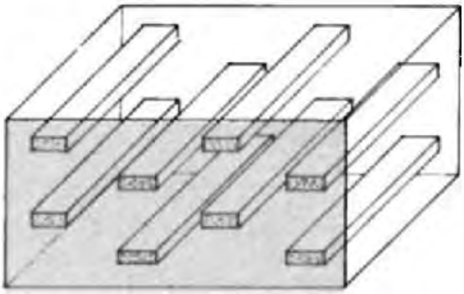
For this purpose, the fence diagram is a very convenient tool in many cases. The situation discussed on the previous pages is shown above in such a fence diagram. It will be seen that the geometry of the separate genetic units can be quite clearly examined: the overall shape of the units; their edges; the interrelationships between the units.

Particularly the last item is quite important, as mentioned on p. 111 (flow paths) and to be discussed further in Chapter H. It is operationally of great interest to form an idea of how fluids could flow through the reservoir complex; the fence diagram allows to form such an idea. Assuming that the clays (the white layers) are impermeable, conclusions on the interconnection of the various units can be drawn.

Unit B1, for instance, is entirely isolated from the other units within the area of study. The two channel sands are in contact across an erosion surface; assuming that the erosion surface allows fluids to pass through, which is not certain, the two units are interconnected. Channel sand C2 and barrier sand B2 are joined over a large area and may be assumed to be one reservoir.

SIMPLIFICATION





In the case shown in the fence diagram on the preceding page, the flow of fluids is controlled by the shape and interconnection of individual sand bodies. The characteristics of the fluid flow, however, can also, and perhaps more commonly, be affected by permeability variations within one continuous reservoir rock body (inhomogeneities, anisotropies).. The upper block diagram above represents a body of sand of a given permeability, in which are embedded channel-type sand bodies of higher permeability, say, higher by a factor 10. Obviously, if a pressure gradient exists in the body from left to right, the flow of the fluids will be quite different from what it would be if the gradient were from front to back.

Such movements of fluids are the subject of reservoir engineering calculations, say, in aid of planning supplementary recovery operations (ref. p. 111). The geometry of the permeability distribution has to be introduced in these calculations with the help of a model. The upper diagram, although already a severe simplification of the natural reality, presents obvious difficulties if it is to be expressed by a mathematical formula. Thus further simplification is necessary and the lower diagram presents a possible model. The direction of the more permeable streaks is derived from the average directions of the channel sand bodies. The cross section is obtained from statistical data on channel dimensions, either measured in the field or derived from literature.

The design of such models is one of the main areas of close cooperation between production geologist and reservoir engineer, often with the help also of the log interpretation expert.

D.9 REVIEW

In Chapter C, the description of the *external geometry* of the reservoir, as a result of the production geologist's work in the field of structural geology, was discussed.

In the present chapter, the analysis and description of the *internal structure* of the reservoir was dealt with. Admittedly in a rather superficial manner, mainly because the subject is so complex that only the surface can be scratched within the confines of this book. For the same reason the production geologist, in this part of his study of a field, will probably have to rely to a considerable extent on the cooperation of specialists in sediment description and log interpretation

It was attempted to stress that two approaches are of prime importance in the sedimentological study of a reservoir.

In the first place it is desirable, if not imperative, to define as accurately as possible the environment in which the rocks of the reservoir were deposited. The research of the recent decades has provided the geologist with models of the rock bodies deposited in many environments in which potential reservoir rocks can be formed. With the help of rock samples, palaeontological and palynological data and logs, the geologist can in many cases define the environmental origin of his reservoir rocks with fair reliability.

The other approach is the very detailed correlation of the logs, in order to dissect the reservoir into the smallest definable genetic units. With the help of the conceptual models provided by the environmental knowledge, these units can then be mapped individually as realistically as possible.

The practical application of this information is mostly as input for the activities of other specialists within petroleum engineering. In consequence, the production geologist cannot content himself with just providing his view of the internal reservoir structure: he must understand the requirements of the other specialists so as to present his knowledge of the reservoir structure to them in the most convenient way. And he must cooperate with them to ensure that his knowledge is used to the best advantage for the common objective of optimizing the field development operations.

The production geologist's description of the reservoir is now complete. The following chapters will deal with the *contents* of the reservoir. Chapter E will discuss the composition of the reservoir fluids; Chapter F will describe their spatial distribution through the reservoir.

Chapter E

RESERVOIR FLUIDS

E.1 PRINCIPLES

Analysis of the composition and other characteristics of the reservoir fluids and the portrayal of their variations over the field area are just as much a part of the production geological description of the field as are its tectonics and stratigraphy.

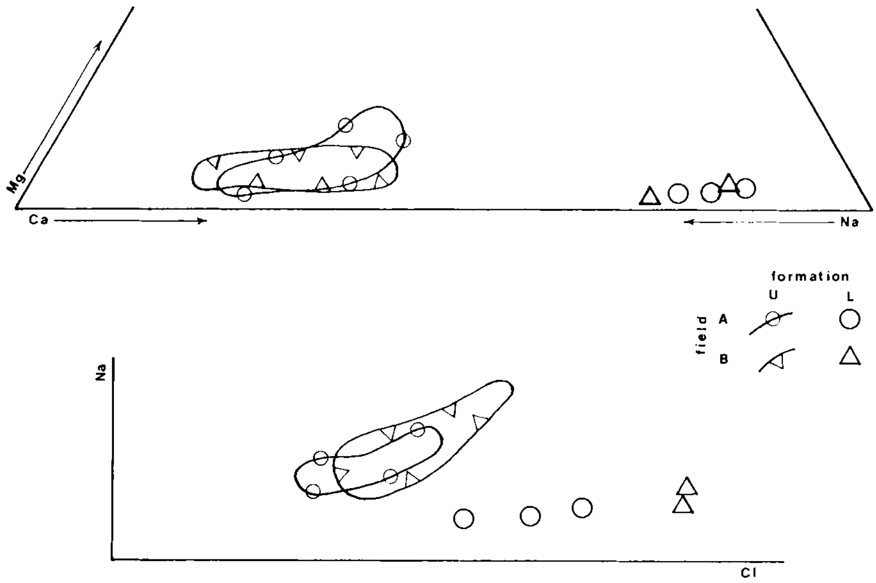
Whereas the composition of the hydrocarbon mixture within one continuous reservoir is usually fairly uniform, the oil contained in separate reservoirs within the same field can be of quite different composition. Thus, if two wells produce different crudes from the same stratigraphic horizon, it is likely that the wells produce from separate reservoirs; the geologist should then attempt to discover the nature of the separating barrier. Moreover, it is of great practical importance to have a good picture of the distribution of different crude types through the field area: it is generally desirable to keep production of different crudes separate ('segregated') and provision for this possibility has to be made in the planning of the field facilities.

In practically all fields there are reservoirs in which only water is contained. These may be reservoir horizons which contain hydrocarbons elsewhere or those which are water-bearing over the entire field area. Separate reservoirs often contain waters of different composition.

Analyses of crude, gas and water produced from the wells in a field are regularly made for operational purposes. It is up to the production geologist to ensure that these are properly recorded, to define different types and to map the distribution of these types over the field.

E.2 FORMATION WATER

CLUSTER ANALYSIS

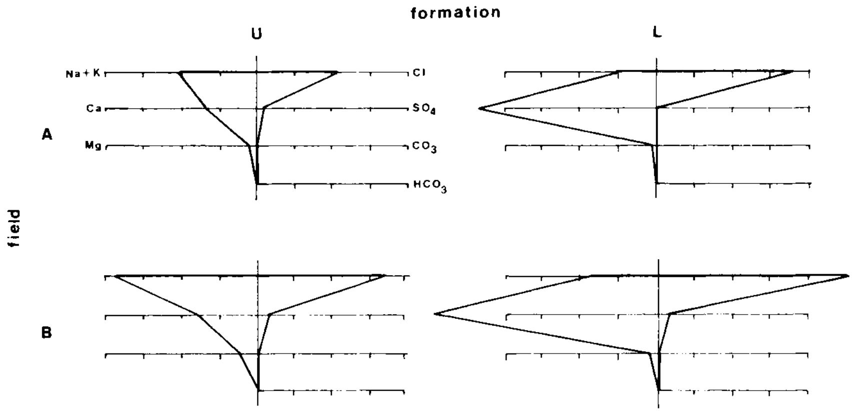


In fields of any size considerable numbers of samples of produced water have usually been collected and analyzed. In order to make a comparison of such numbers of analyses, it is convenient to cross-plot the concentrations of two or three ions. Samples known to have been derived from different reservoirs are marked by different symbols on the plots. If recognizable types exist, they will show up as separate clusters of points.

The two graphs represent samples from two fields and two reservoir formations in each field. The upper formation U is the best producer and many samples were available. The resulting clusters, shown in outline only, prove that the waters from both fields are quite similar but not identical. The lower formation L, from which only few samples were available, is quite different in water composition from the upper formation, even though in both fields the two formations are in pressure communication.

If the existence of recognizable water types has been established, their spatial distribution can be shown by symbol or colour coding on maps, stratigraphic sections, etc.

ILLUSTRATION



If it is desired to show more detail of the water compositions graphically, a selection can be made of various systems. One of these is shown above: the concentration of seven ions is shown on the seven axes at a convenient scale (which need not be the same for all ions). Other systems are slightly different: in one system the axes are not parallel but radiate from a common centre at angles of 60 degrees; in others the concentrations are shown as heavy bars along the axes.

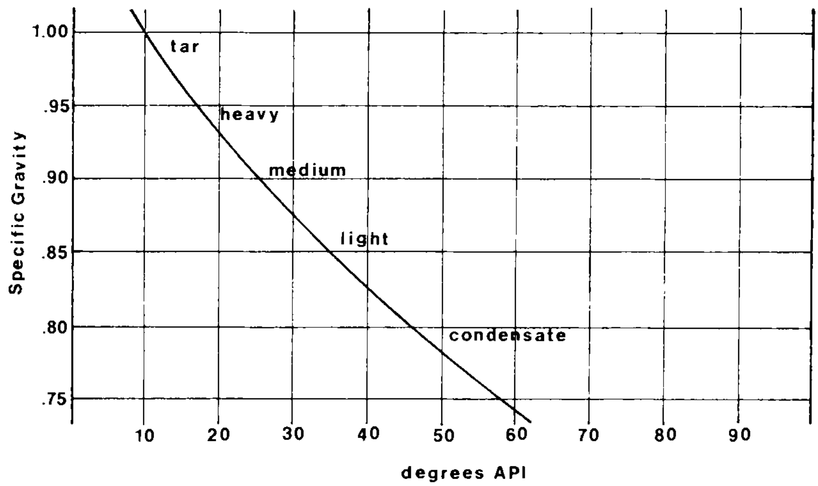
These systems are effective for illustration purposes. From the diagrams above it can be seen immediately that the main difference between the waters in the two formations lies in the proportion of sodium (including minor amount of potassium) to calcium. The total concentration of dissolved matter is higher in field B than in field A and in formation L than in formation U.

Water types can vary, not only between separate reservoirs, but within one single reservoir. It is not uncommon, for instance, that there is a difference in composition between the so-called connate water, present in the pore space of the hydrocarbon-bearing portion of a reservoir, and the edge-water in the fully water-saturated portion. It should be noted that such a condition can lead to difficulties in log interpretation: the composition of the connate water is to be used in saturation determinations from logs, but the analyses available may represent the edge-water.

An important practical application of the knowledge on water types and their distribution in different reservoir zones is the determination of the origin of water produced with the oil from a well. Such produced water can be derived from the same reservoir which produces the oil, in which case the start of water production probably means that the edge-water has encroached to the vicinity of the producing well. But it is also not uncommon that water enters a well in some other way, the most common being a leaky casing string. In this manner water from a different reservoir horizon can enter the well. If the distribution of different water types has been carefully investigated, it is may be possible to determine where the leak in the casing is located and proper remedial measures can then be taken.

E.3 CRUDE OIL

CRUDE GRAVITY



Crude oils are very complex mixtures of various hydrocarbons in various proportions. Highly sophisticated analysis techniques have been developed to determine the composition of a crude oil in terms of the component hydrocarbons. The results of such analyses can be used to 'type' or 'fingerprint' a crude sample. These methods, however, are expensive and time-consuming and will be used only for special purposes. In everyday oilfield practice simpler techniques are used.

In any well-run oilfield all producing wells are sampled regularly and at frequent intervals. The property that will undoubtedly be measured on all these samples is the density of the crude oil, in oilfield terms called the crude gravity. This parameter can, of course, be expressed as specific gravity. But, in practice, use is often made of the system introduced by the American Petroleum Institute in the early years of the oil industry. The conversion from specific gravity to API gravity is shown graphically above. It will be noted that heavy oil, i.e. oil with a high specific gravity value, has a low API gravity number, and vice versa.

Crudes are roughly classified on the basis of their gravity. The terms in common use are shown in the figure, but is should be noted that there are no sharp and commonly accepted definitions of the various classes.

Apart from the routine gravity measurements on crude samples from wells, these samples will at intervals, but less frequently, be analyzed more fully in accordance with some standard system; standard analysis procedures and units of measurement have been established by the industry. The parameters usually included are the following:

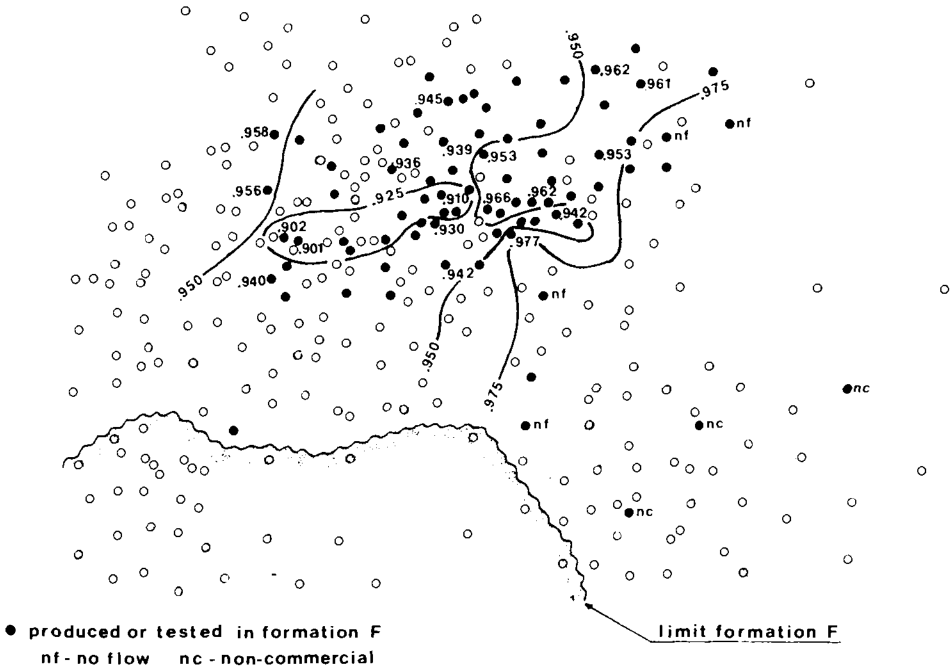
Specific Gravity
Viscosity
Pourpoint
Flashpoint
Wax content and setting point of the wax
Sulphur content
Distillation (amount of fluid distilled over in a series of temperature steps).

In most fields numerous analyses of this type will be available and the production geologist can use them to investigate whether significant variations in crude type exist in his field and to set up a classification into different types if possible. For this purpose it is convenient to use a similar cross-plotting technique for cluster analysis as described for formation water investigations (Section E.2).

Probably the most convenient couple of parameters for cross-plotting are gravity and viscosity. For each type of crude these two properties are closely related, in the sense that viscosity increases with crude specific gravity, but for different crudes the relation is not identical. Therefore, different crude types in a field are likely to show up clearly as different clusters on a gravity-viscosity cross-plot.

The type of crude produced from a well of course depends on the reservoir from which the well is producing. It is not uncommon that a well's production changes its characteristics during the life of the well. This usually means that the well is producing from two different reservoirs, each with its own crude type, and that the contribution of each reservoir to the well's total production changes with time.

GRAVITY MAPPING

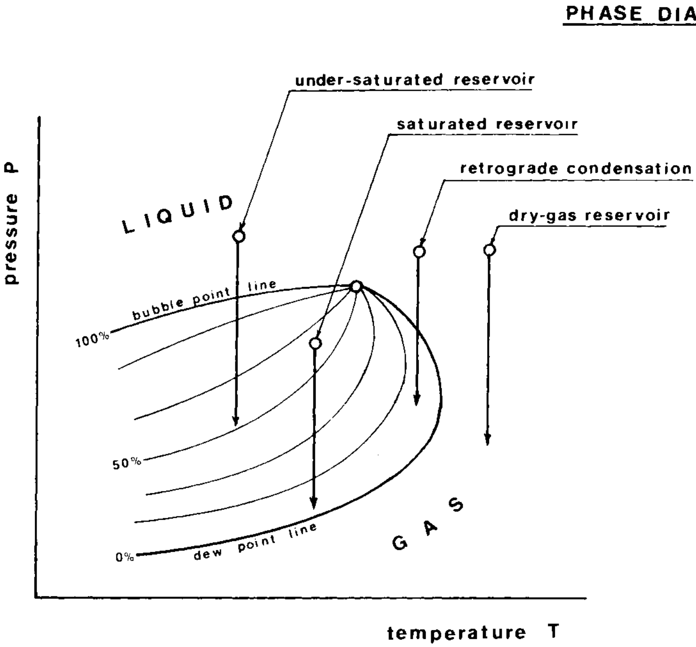


The map represents part of an old oilfield, where the many wells produced from a thick section with many sand intervals. Three different formations can be recognized, each containing many small sand bodies, largely uncorrelatable from well to well, partly oilbearing and forming more or less separate reservoirs.

The gravity of the oil in the sands of formation F varies from about 0.900 to over 0.975. The lowest values – lightest oil – are concentrated in the centre of the mapped area and the wells producing from F-sands are to be found in this vicinity. To the southeast lies an area where the F-sands are present and oil-bearing, but not sufficiently productive to achieve commerciality. The cause of the poor productivity is obviously that in this area the oil in the F-sands is heavy (over 0.975) and, therefore, too viscous to flow, even in the reservoir at the elevated subsurface temperature.

The question may be asked – in this as in many other cases – how this distribution of oil gravity came about. To answer this question is difficult, if not impossible, in most cases. The production geologist is generally reduced to observing the facts and adapting the development plans to the conditions found, in order to avoid drilling wells that may be unproductive because of unfavourable crude properties.

E.4 PVT ANALYSIS



Because of the complex composition of the hydrocarbon mixtures in reservoirs, the phase behaviour of the mixtures, when conditions of pressure, temperature and volume change, is also complex. Because knowledge of the process for any particular reservoir fluid is important for field production planning purposes (ref. Section H.2) 'bottom hole' samples are taken in producing wells, with due precautions to ensure that the samples are indeed representative of the reservoir fluid. Such a sample is then enclosed in a cell in which the volumes of liquid and gas can be measured as the temperatures and pressures are varied; this is called PVT analysis.

The result of a full PVT analysis of a crude sample is shown schematically in the figure above. It shows that in the case of a crude/gas mixture there is no sharp line separating the regions of '100% liquid' and '100% gas' – as is the case when e.g. water is boiling off – but an area in which the proportion of liquid and gas changes gradually as pressure and/or temperature are changed.

When the first well enters a reservoir, the pressure and temperature in the reservoir are at a certain value, known as the initial or virgin pressure and temperature. During subsequent production, volumes of reservoir fluid are withdrawn from the reservoir. Assuming, for the time being (but see Chapter H), that the reservoir volume does not change and that the temperature in the reservoir does not change appreciably – which is practicallly certain – the only parameter that changes in the PVT diagram is the pressure.

The initial pressure/temperature condition is represented by a point of the PVT diagram and the isothermic process of pressure decline, that results from production, shows up as a vertical line downward. In different types of reservoir, different phenomena result. (In the figure on the preceding page the differences in reservoir conditions are represented by different starting points. In reality, the shape and position of the patterns of iso-saturation lines should be changed as well, but this was omitted for the sake of simplicity.)

A reservoir, in which initially no free gas is present, is called an 'under-saturated' reservoir or a reservoir containing under-saturated crude. As pressure decreases, a point will be reached where the first bubbles of free gas appear in the liquid: the bubble point. With further pressure decline the proportion of gas to liquid increases, in the reservoir as well as in the produced hydrocarbon mixture.

In many reservoirs conditions are such that initially free gas could exist: reservoirs with saturated crude or saturated reservoirs. Under the influence of gravity force the gas will concentrate in the highest part of the reservoir, where it will form the gas cap. As pressure decreases during production, additional gas is freed from the liquid column in the reservoir and will travel upwards to increase the gas-filled volume. (Assuming of course that no free gas from the gascap is produced.)

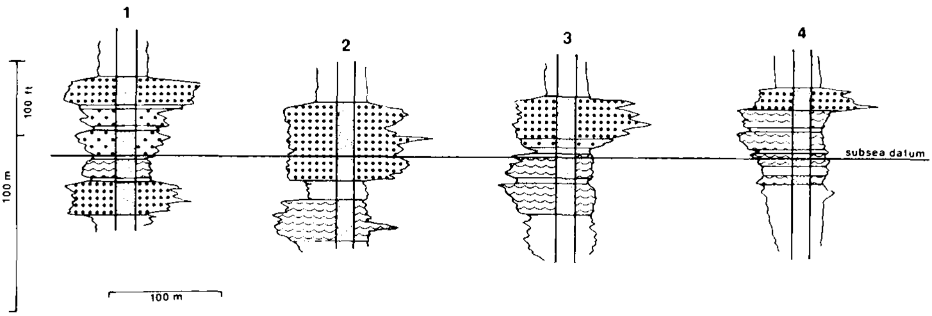
Many reservoirs contain no liquid hydrocarbons at all, the so-called dry-gas reservoirs. Normally, if the gas is produced the pressure will decrease without any phase change in the reservoir. However, in some cases a process called retrograde condensation can take place: whereas normally a gas will turn into a liquid only when the pressure is increased (normal condensation), some hydrocarbon mixtures are composed such that the original gas in the reservoir will form liquid if the pressure is decreased.

In a producing well the fluid and/or gas enters the well at a certain pressure: the bottom hole pressure or BHP. As the mixture travels upwards in the well bore, the pressure decreases and the liquid/gas ratio will change correspondingly. Hence the gas/oil ratio or GOR increases as the oil flows from the reservoir to the well-head. When the oil finally enters the storage tank (via separators) the conditions are reduced to atmospheric pressure and temperature and the gas, appropriate for those conditions, has been removed (ref.p. 209). Similarly, if a well receives only gas from the reservoir, some of the heavier hydrocarbons contained in the gas may be in liquid phase at atmospheric pressure and temperature; such liquids are removed from the gas stream as 'condensate' (comp.p. 139).

Chapter F

ACCUMULATION CONDITIONS

F.1 INTRODUCTION



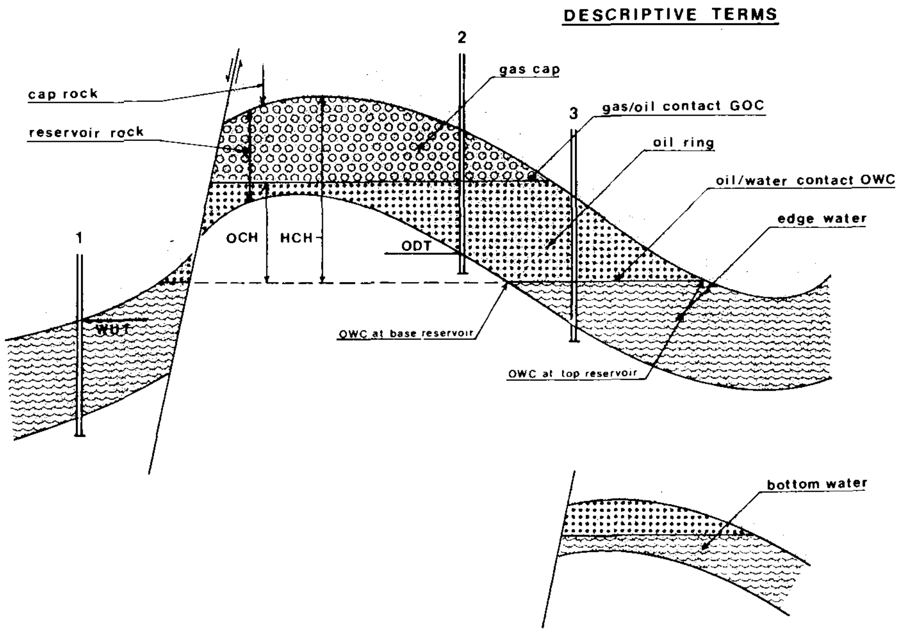
The structural geology work has portrayed the external geometry of the reservoir and the sedimentological work has provided a picture of the internal structure. It now remains to analyze and describe the distribution of the hydrocarbons within this complex of deformed rocks.

The question of how these accumulations came about can in most cases be answered only in part, and in many cases not at all. Explorationists are familiar with the general conditions, which have to be fulfilled in an area if hydrocarbon accumulations are to be formed: presence and maturity of source rocks; existence of suitable migration paths; presence of reservoir rocks and cap rocks to form traps; etc. However, these explain only in general terms the likelihood of accumulations existing. But the details of the distribution of hydrocarbons within the complex arrangement of reservoirs, which most oilfields are, are not generally clearly understood. In many fields there is a multiplicity of potential reservoirs and the question why there is oil in some of these and none in others can only rarely be answered with any confidence.

The penetration chart above shows such a case in an old oilfield, where each well penetrated a series of sands wih thin shale breaks in between. Despite the short distance between the wells, correlation of the sands is impossible and a reliable understanding of the oil distribution even more so. Study of the field suggested that, within a monoclinally tilted formation, many small channel-type sands exist, part of which apparently form local traps in which the oil, migrating updip, could be retained.

The practical consequences of such uncertainty can be illustrated if it is assumed, for instance, that only wells 1, 2 and 3 have yet been drilled and that the geologist is required to provide a prognosis of the sand distribution and thc position of potentially productive intervals at the location where well nr. 4 is to be drilled.

F.2 DATA AND TECHNIQUES



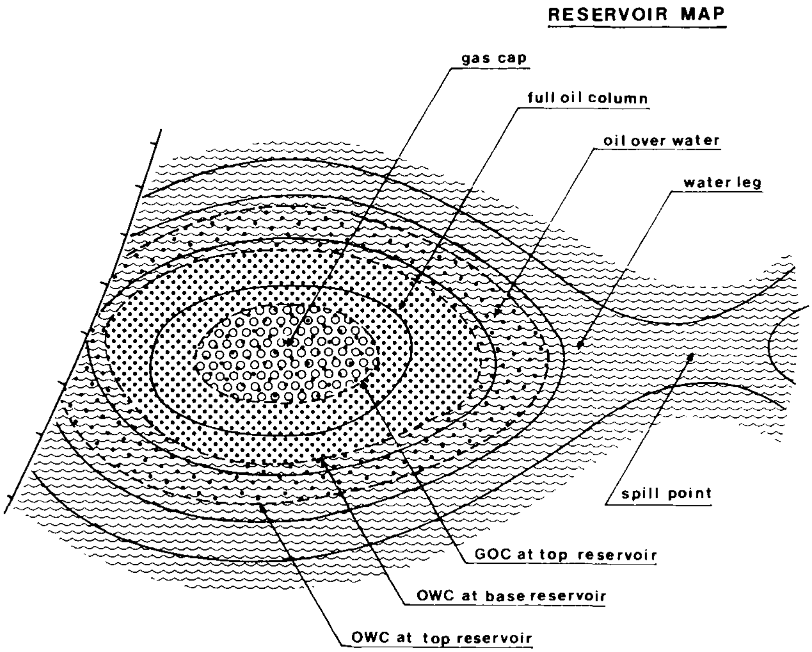
For the sake of completeness, the terms most commonly used in the description of hydrocarbon accumulations are illustrated above.

The section shows the reservoir rock, covered by the cap rock, below which the hydrocarbons are trapped.

If free gas is present, it forms the gas cap which overlies the oil ring; the interface between the two zones is the gas/oil contact or GOC. Below the oil, in turn, is the water which fills the remainder of the reservoir space; oil and water are separated by the oil/water contact or OWC. If, as in the upper section, the water does not underly the entire oil accumulation, the term edge water is used; otherwise, one speaks of bottom water (see lower section).

As the OWC is of great practical importance, several standard terms express spatial relations with respect to the level of the oil/water contact. The maximum total height of the hydrocarbons above the OWC, i.e. the distance to the highest point of the reservoir, is called the HCH, hydrocarbon column height; the thickness of the oil ring is the oil column height, OCH.

Well 3 has penetrated the OWC and thus gives direct information on the depth of the contact. Well 2 penetrated the bottom of the reservoir before reaching the OWC: it contributes only a minimum possible depth, which is referred to as the 'oil-down-to' or ODT depth. On the other hand, well 1 went straight into the water leg and provided a maximum possible depth for the OWC: the 'water-up-to' or WUT depth.



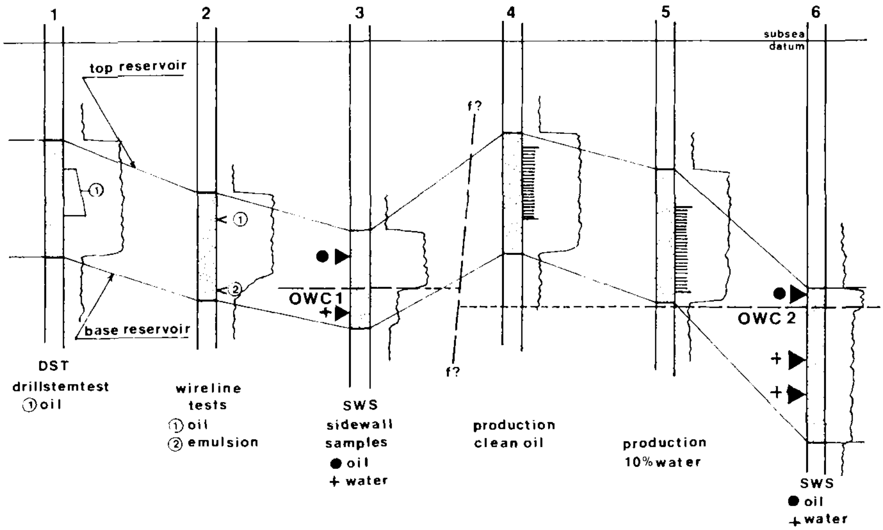
The figure above illustrates how the distribution of gas, oil and water is depicted in map view; the map being a contour map on the top of the reservoir, such as is most commonly used in practical planning work.

The GOC and OWC are – essentially – plane, horizontal surfaces, which therefore intersect Top Reservoir along horizontal lines, showing up on the map as lines parallel to the nearest contours.

Adjacent to the intersection of OWC with Top Reservoir is a strip, where the oil is underlain by water; the inner limit of this strip is the intersection of OWC with Base Reservoirs (comp.figure on previous page). It is important to show this strip on planning maps because wells drilled into this strip will encounter water (ref. well 3 on the preceding page) before the entire thickness of the reservoir zone has been drilled through.

It is generally accepted that hydrocarbon accumulations are formed by hydrocarbons, in the form of minute droplets or bubbles, wandering into the structure, travelling upwards in the reservoir rock and being trapped by the inverted bowl of cap rock overlying the reservoir. This process can, in principle, continue until the OWC has been lowered to the level of the highest point on the rim of the reservoir; depth and position of this point, the spill point, are indicated by the highest 'non-closed' contour on Top Reservoir. Any additional hydrocarbons entering the structure will not be trapped but escape at the spill point. The largest possible volume has then been trapped in the structure and the reservoir is said to be filled to capacity; most reservoirs, however, are not full.

PENETRATION CHART



The data used for the study and description of accumulation conditions are in large part not strictly geological in nature, but the geologist has to collect them and display them in a manner that is convenient for his purposes. A useful tool is the penetration chart. Like the correlation chart (ref. p. 22) and the structural section (p. 56), it consists of a number of sections of well logs. But in this case these are hung on a topographic (subsea) datum and not located to a horizontal scale but arranged in such a way that accumulation conditions can be observed as clearly as possible.

Probably the most important and most frequent objective is the location of the OWC in a field. The main category of information comes from logs; especially the resistivity log, shown schematically above, indicates the position of the OWC in a well where it has been penetrated. A very useful contribution may come from sidewall samples (SWS) which are often taken in wells for the specific purpose of helping locate the OWC with accuracy (wells 2, 3 and 6). For the same purpose of distinguishing between potentially productive and waterbearing intervals, so-called tests may be arranged: drillstem tests make use of the string of drillpipe and wireline tests are taken with a special tool run on the logging cable. The DST in well nr 1 and one wireline test in well 2 found oil; the other test in 2 found emulsion, indicating proximity to the OWC. The clean oil produced in well 4 suggests that the producing interval (hatched) is well above the OWC; the 'water cut' of 10% in well 5 indicating that the OWC is close to the producing interval.

The result of the entire analysis is that the OWC in wells 2 and 3 appears to be somewhat higher than that in wells 4, 5 and 6. This in turn suggests that two separate reservoirs exist, probably separated by a fault.

INVENTORY OF HYDROCARBONBEARING INTERVALS

	WELL Nr D.F.Elevation	F-9 121		F-12 132			
SAND NAME		bdf	ss	bdf	ss	bdf	ss
A-5	TOP SAND	2643	2522	2535	2403		
	GOC OWC	- 2710	2589	2552 NR	2420		
	ODI WUT			2695	2563		
	BASE SAND	2798	2677	2695	2563		
	NGS NOS	53		14 113			
B-1	TOP SAND	2850	2729	2768	2636		
	GOC OWC	2862 2914	2741 2793	2872 2923	2740 2791		
	ODT WUT						
	BASE SAND	2967	2846	2945	2813		
	NGS NOS	9 41		89 40			
B-3	TOP SAND	NR		3167	3035		
	GOC OWC						
	ODT WUT			3167	3035		
	BASE SAND			NR			
	NGS NOS						

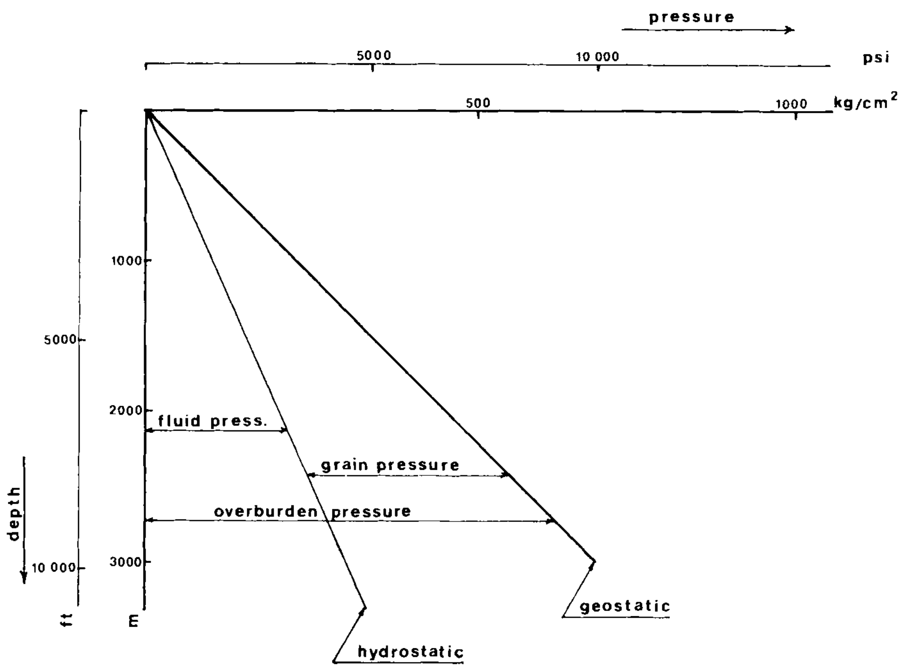
Measurements in feet.

Many fields have several – or even many – separate reservoir horizons and several tens of wells. To assemble and record all the relevant data for each reservoir sand in each well is a major administrative exercise. Some type of formal record form is likely to be required and an example of such a system is shown above; obviously, the system has to be adapted to the conditions in the field in question. Also, it is clear that an administrative system like this is well suited for computerization.

In the example the depths, both below derrick floor and subsea, of all levels of interest are included. In addition, space is provided for entering also the net sand thicknesses; these figures are of interest for reserve estimating and their inclusion makes the inventory into a useful document for this purpose as well.

F.3 CONTROLLING CONDITIONS

SUBSURFACE PRESSURES



In the upper portions of the earth's crust, in which the oil industry operates, all pore space is saturated with water (below the phreatic surface).

At depth in the subsurface, the overlying mass of sedimentary material and pore fluid exerts a (pseudo-)pressure, called the overburden pressure. This pressure increases with depth at a gradient which is referred to as the geostatic gradient.

In principle, the fluids in the pores of the rock form a continuous fluid column from near the surface. The pressure in this column increases with depth – in normal conditions – in accordance with the hydrostatic gradient.

The grains of the rocks 'carry' each other by forces exerted at the contact points. This network of forces is not, strictly speaking, a pressure, but can by approximation be viewed as such. It is called the grain pressure.

At any point at depth in the crust:

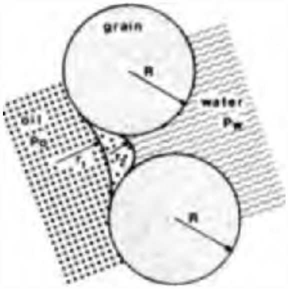
fluid pressure + grain pressure = overburden pressure.

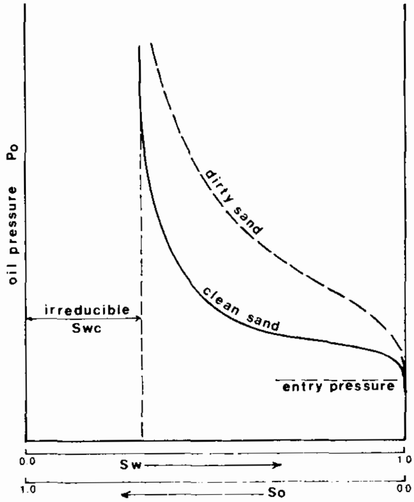
It is useful to remember the following commonly occurring values for the important pressure gradients:

hydrostatic gradient: 0.1 $kg/cm^2/m$ or 0.43 psi/ft

geostatic gradient: 0.8 – 1.0 $kg/cm^2/m$ or 1.0 psi/ft

CAPILLARY PRESSURE





When the accumulation was formed, the hydrocarbons, which had migrated from the source rock to the reservoir rock, had to make their way into the pores of the reservoir rock, which were already saturated with water. As most reservoir rocks are water-wet, and not oil-wet, the capillary force opposes this movement of oil into the water-saturated pores. The capillary force, as it were, attempts to keep the interface between oil and water as flat as possible. Consequently, in order to force the oil into the pores, the pressure in the oil, *Po,* has to be higher than the pressure in the water, *Pw*. The difference is the capillary pressure:

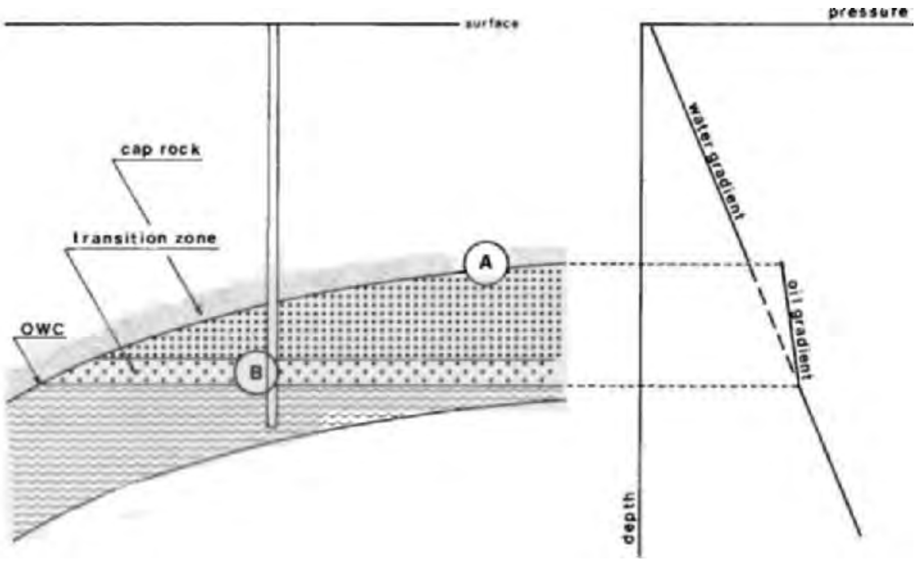
$$Po - Pw = Pcap = f(r^{-1}, R^{-1})$$

$$r_2^{-1} > r_1^{-1} \rightarrow \text{increasing } Pcap$$

The capillary pressure is a function of the curvature of the interface (r). As the oil penetrates farther into the pore, this curvature increases and, consequently, the capillary pressure increases: in other words, the oil pressure must be higher with respect to the water pressure in order to force the oil farther into the pores.

This can be measured empirically by forcing a non-wetting fluid (mercury) into the pores of a water-saturated sample of reservoir rock. The resulting curve of 'oil' saturation, *So,* vs. oil pressure, *Po,* is shown above. An initial entry pressure has to be overcome to force any oil into the pores. And finally, a certain irreducible water saturation remains.

As the capillary pressure also depends on the curvature of the grains of the rock, it is easier to force oil into the pores of a 'clean', well-sorted, coarser sand, than into a 'dirty', poorly sorted, argillaceous sand.

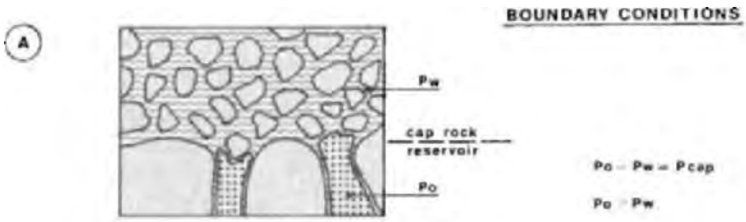


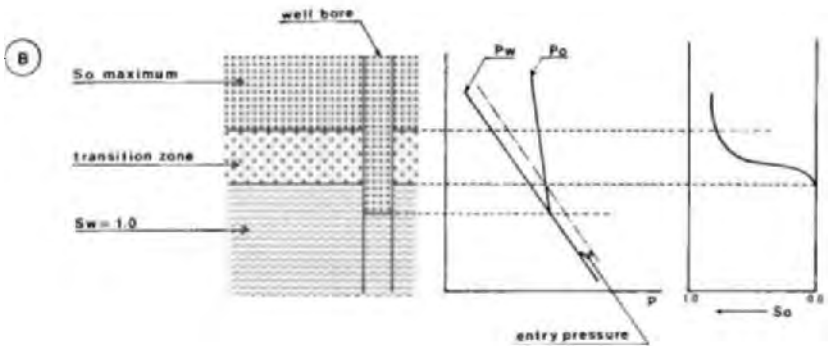
The pressure Pw in the formation water in and around the reservoir increases with depth, in accordance with the hydrostatic or water gradient.

In the, partly oil-saturated, portion of the reservoir rock, however, conditions are more complex. At the lowest level of oil saturation in the reservoir, i.e. at the oil/water contact, the pressure in the oil is equal to the pressure in the formation water (if the capillary pressure is disregarded for the moment).

Above this level, there is a continuous oil column up to the top of the reservoir zone. In this column the pressure decreases in an upward direction, but at a smaller gradient than the water gradient; this is so, because the density of the oil is less than that of the water. In consequence, there is an increasing difference between Po and Pw as one goes upward in the reservoir, with its maximum at the base of the cap rock.

These pressure conditions play a major part in controlling the shape and position of the oil accumulation, as will be demonstrated on the next page.



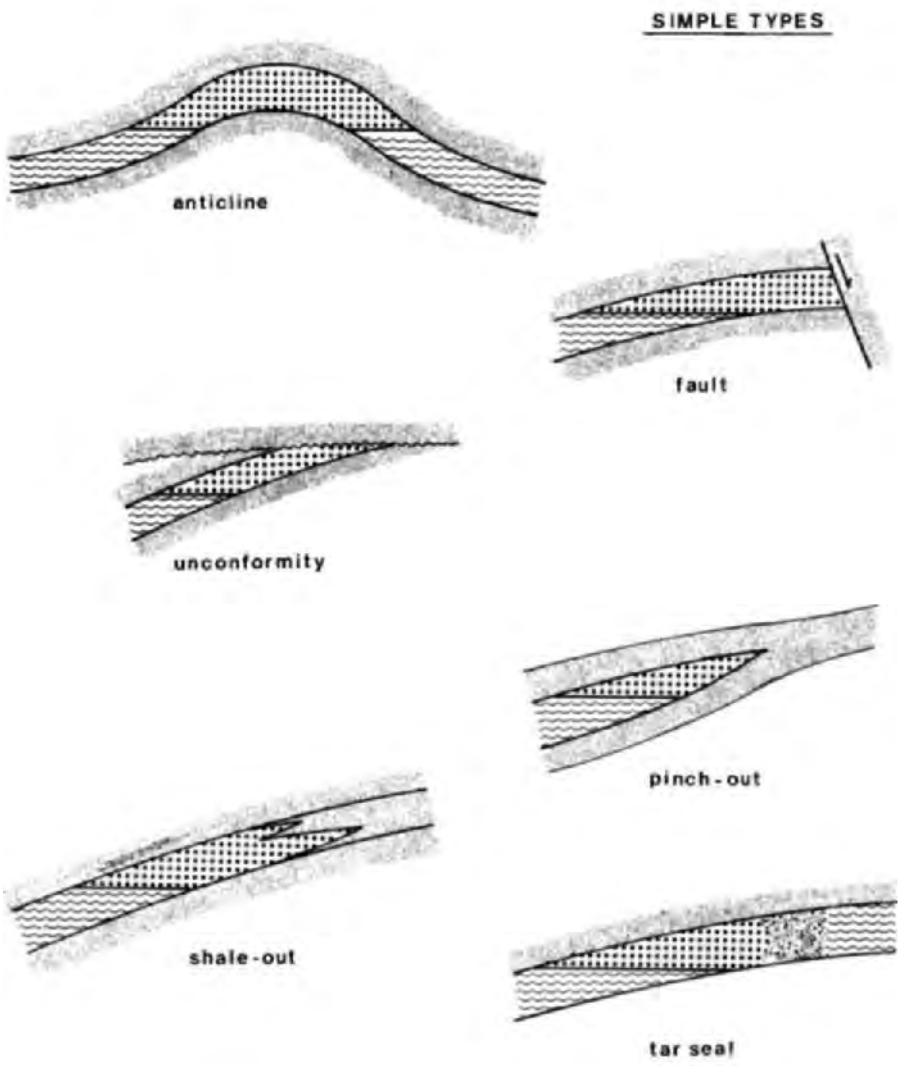


The upper figure sketches conditions at point A in the figure on the preceding page. In the larger pores between the coarser grains of the reservoir rock, oil is present and its pressure is higher than that in the surrounding water. Because the cap rock, per definition, prevents the oil from migrating upwards, the pressure difference is obviously not large enough to make the oil penetrate into the narrower pores between the finer grains. In other words, the cap rock is impermeable to oil, but the water content of reservoir and cap rock is continuous.

The lower figure represents conditions in and around the well bore at the OWC. If the fluids in the well are left at rest, a free water level will establish itself: at this level the pressure in oil and water must be equal. For oil to be present in the pores of the reservoir rock, the oil pressure has to be higher than the water pressure, by an amount equal to the entry pressure. The lowest oil saturation is, therefore, found some distance above the free water level. From this depth upward, the saturation increases in accordance with the capillary properties of the rock, symbolized by the capillary pressure curve. At a certain level the maximum oil saturation is reached, i.e. at the top of the so-called transition zone.

In detail, therefore, there is no real oil/water contact in the rock, but a transition zone of finite thickness between the zone of maximum oil saturation and the zone with 100% water saturation. In practice it is often sufficient to represent the actual situation by a simple OWC depth figure; especially in clean rocks, where the transition zone is thin.

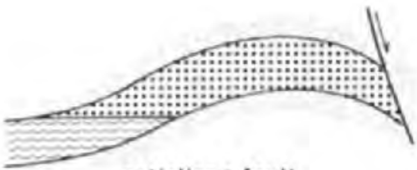
F.4 TRAP TYPES



Classifications of trap types have been made for many years and they are undoubtedly useful for communication purposes, although they carry the risk of oversimplification. A few types are shown schematically above.

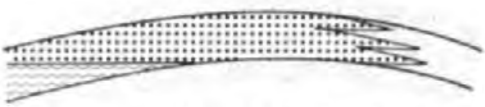
The first three types have their origin in tectonic deformation; the following two are caused by sedimentary conditions. The last one results from alteration of the hydrocarbons in the reservoir: by escape of lighter components or by contact with meteoric water, the viscosity of the oil becomes so high that further travel updip in the reservoir zone becomes impossible; below the resulting tar seal, there may then still be lighter, less modified oil present.

COMBINATION TRAPS

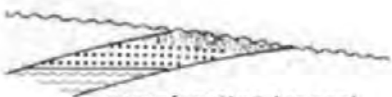


anticline & fault

anticline & unconformity



anticline & shale-out

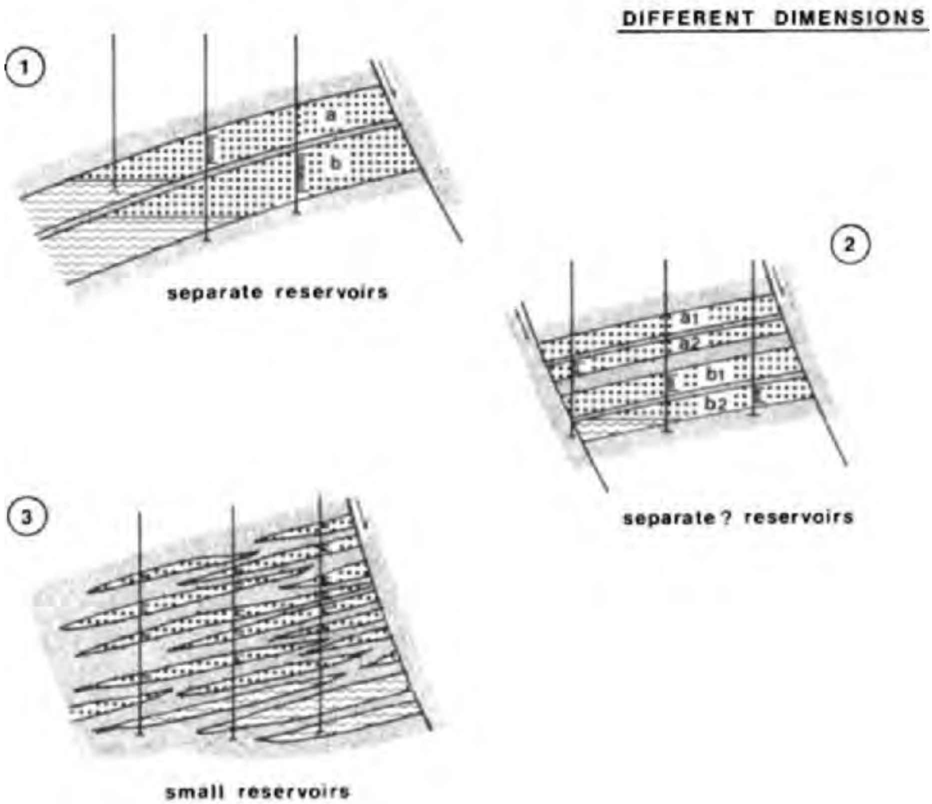


unconformity & tar seal

Classifications of trap types tend to over-simplify: the simple types shown on the preceding page probably are fairly rare in reality. Most traps are in fact combination traps in which more than one 'trapping agent' was active to form the accumulation. Above are schematically shown a few types where two such agents can be recognized, and even these types are simple compared to what occurs in reality.

In considering the accumulations with which the production geologist has to deal, he will be well advised to use his intelligence and his general background knowledge to arrive at the best possible picture of the configuration and the nature of the accumulations. If he contents himself with assuming too simple a type, he will run the risk of drawing erroneous conclusions regarding shape and positions of his reservoirs and, in consequence, of either drilling unnecessary dry holes, or missing additional reserves. Also, the erroneous model may be applied to other structures in the same area whereby potential new oilfields may be missed.

F.5 MULTIPLE RESERVOIR HORIZONS



Situations with important practical consequences are those in which several, or many, reservoir zones occur in a vertical sequence, with relatively thin tight zones between the oil-bearing horizons. The crucial question is whether or not the thin impermeable layers ('shale breaks') are sufficiently effective barriers to make the oil-bearing zones into separate reservoirs.

Case 1 shows two sandy intervals, separated by a thin shale layer. The wells have encountered different OWC's in the two zones; from this fact it may be concluded that the two sands are separate reservoirs. In such a case, wells will generally each be completed in one reservoir as indicated in the sketch.

It is also possible that two similar sands would have the same OWC's; this situation would arise if there is some form of fluid movement possible between the sands, for instance if the thin shale layer is not continuous over the area of interest. If the OWC is the same, it is unlikely that the two sands would be separate reservoirs: the probability that two separate reservoirs should, by coincidence, have their OWC at the same depth is small. The development plan for two sands forming one reservoir will obviously be different from that for two separate reservoirs (ref. Chapter H).

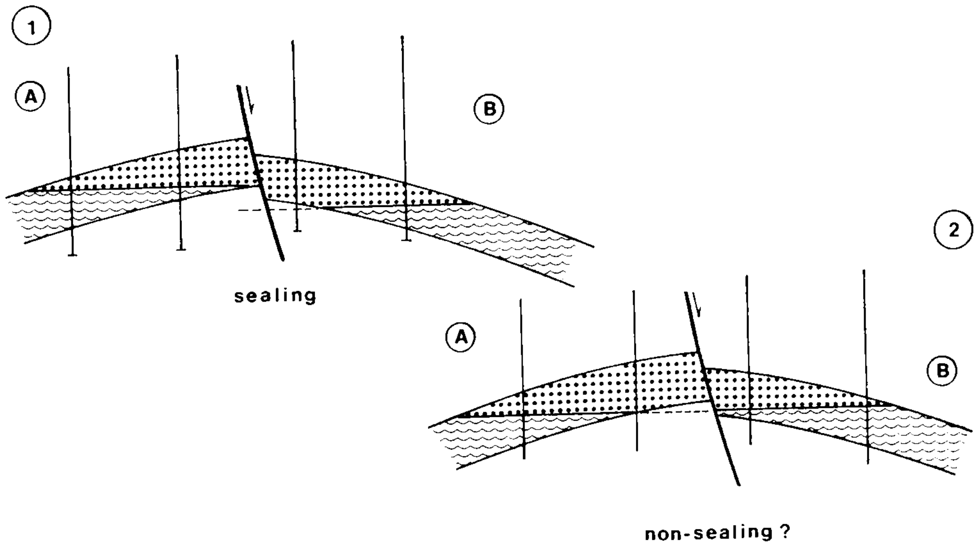
Case 2 presents worse problems: an OWC has been observed in sand b2, but none in the other sands. In the early stages of field development there is probably no way of finding out whether the four sands do or do not form separate reservoirs; in planning the field development, it is probably advisable to assume that the reservoirs are indeed separate, because producing separate reservoirs together is generally undesirable. If it is inadvisable to complete each well on one sand only – perhaps because the foreseen production from one sand is not enough to pay for the well – it may be attractive to combine (commingle) sands a1 and a2: the shale between these two sands is thin and therefore more likely to allow intercommunication between the sands than the thicker shale between the a-sands and the b-sands.

Whether the sands do form separate reservoirs or not, will probably only be established later in the life of the field, when pressure history during production affords additional evidence.

In case 3 the individual sands are so thin that they certainly would not permit separate completions. The wells are then likely to be completed on all the sands penetrated, regardless of their being separate reservoirs or not. The production from the entire group of sands is commingled, each single sand contributing according to its producing capability.

This discussion has been illustrated by sand 'cases'; similar situations are also quite common in carbonate reservoirs.

F.6 SEALING AND NON-SEALING FAULTS



If a fault cuts across a reservoir zone, the question arises whether or not the fault is 'sealing'; in other words, whether or not the fault forms an effective barrier against the flow of fluids from one fault block to the other.

The fault in case 1 is likely to be a sealing fault, because there is a depth difference between the OWC's on either side of the fault. If any fluid flow across the fault had been possible, the differences in pressure between the fault blocks would have been evened out in the long course of geological time and the OWC would have been the same on both sides.

In case 2 the OWC is the same on both sides, indicating that the fault is probably non-sealing: the probability that the two OWC's are at the same depth purely by coincidence is very low.

Things become less simple, however, once production starts. As a result of the removal of fluids from a reservoir, the pressure in the reservoir will, in many cases, go down. It is unlikely that the pressure decline will be equal in the two blocks on either side of the fault. Thus a pressure differential across the fault is likely to be caused during production and there are different ways in which the fault can react to such a differential.

If the sealing capacity of the fault is fully effective, the pressure difference will be maintained in its full magnitude.

Cases occur, however, where the seal is fully effective only as long as the pressure differences are small. If the pressure decline in, say, block B is much larger than that in block A, a breakthrough may occur and pressure equalization across the fault will result. Such phenomena can be established by careful analysis of the pressure history of individual reservoirs.

In case 2 a comparable difference between the long-term and the short-term pressure effects may occur. It was assumed that the fault is non-sealing, because the fluid and pressure conditions on both sides have fully evened out. But it is still possible that the fault does act as a barrier when production starts and creates a pressure differential between the two fault blocks. Assuming that the fault is non-sealing, it would be expected that the pressure decline on both sides would be the same; but in practice this is not always the case: the long-term non-seal may prove to be a short-term seal.

Also, it is possible that a fault is only a partially effective seal. Assume that in case 1, where the evidence shows a sealing fault, production is confined to block B, block A being left undrained (for the time being). If the fault were fully sealing the pressure in block A would not decline, no fluid being withdrawn. It is possible, and in fact not uncommon, that the pressure in block A does go down, albeit not as fast as in block B: the seal is partially effective to the short-term pressure effects caused by production.

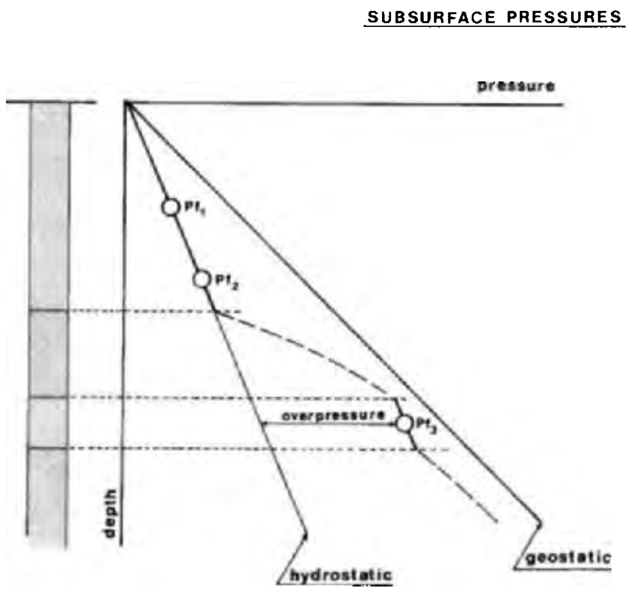
So far, the discussion has dealt only with faults as seals. It is possible also that faults are, in fact, channels for fluid communication, not only across the fault, but along the fault: miners are only too familiar with the phenomenon of water break-in when the workings approach a fault. Similarly, fluids may move from one reservoir to another by faults acting as communicating channels.

How do these different properties of faults come about? The question is so important for field development, that much research has gone into finding an answer. In some geological environments some headway has been made in solving the problem, but no general laws have been established.

Many faults are not simple planes but in fact more or less wide zones of fault gouge; it is likely that such zones of fine-grained gouge will tend to act as seals. If on the contrary the fault walls are some distance apart without any gouge present, the chances are, of course, good that the fault will act as a channel for fluid flow.

In practice it may be permissible to start from the assumption that faults will tend to be sealing if the rocks in the reservoir formation are poorly consolidated: it seems not unlikely that those conditions are favourable for the formation of a gouge seal. On the other hand, non-sealing faults appear to be more common in formations which are well-consolidated. But these are only very tentative rules and the geologist should be prepared for all possibilities.

F.7 ABNORMAL PRESSURE

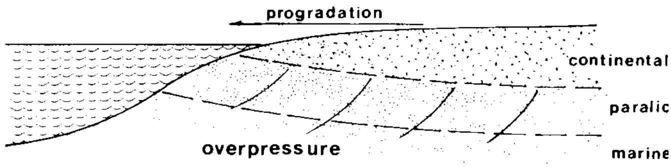


Pressure conditions normally prevailing in the subsurface were outlined in Section F.3. The conditions in the upper part of the figure above conform to these normal conditions: the measured fluid pressures Pf_1 and Pf_2 show a normal hydrostatic gradient.

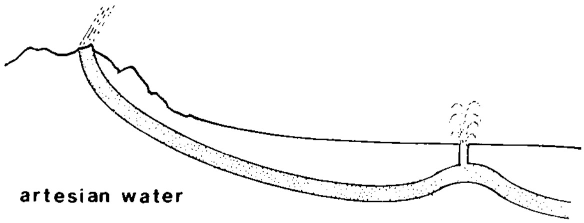
Now let us assume that the figure represents a subsiding area in which the sediment sequence has been deposited at high speed. With depth the increase in overburden pressure leads to increasing compaction and thus to decreasing pore volume in the rock. This, in turn, means that fluid has to be expelled from the rocks and the only way of escape is upwards. As long as the permeability of the rock package is high enough, this escape will not take long and the normal hydrostatic gradient will be maintained, as in the sandy upper section in the figure.

However, if the permeability of the rocks is poor, or if a poorly permeable interval is intercalated as in the figure, the fluids will not be allowed to escape rapidly enough and the increasing fluid pressure in the pores will not allow the rock to compact in accordance with the full overburden pressure; in other words, the pore fluids partly 'carry' the grains. If at such depth a fluid pressure is measured, which is usually possible only in sandy intervals, a pressure will be found which is higher than it would have been in normal hydrostatic conditions; the actual pressure measured will be closer to the overburden pressure (in accordance with the geostatic gradient). The excess of the actual measured bottom hole pressure over the hydrostatic pressure, corresponding to the depth of the measurement, is referred to as the 'overpressure'. (Also called 'geopressure', a not very satisfactory term.)

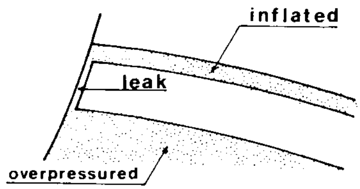
CAUSES OF OVERPRESSURE



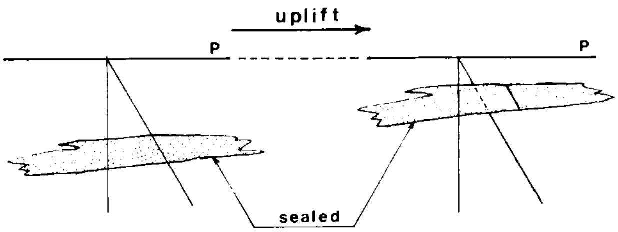
sediment loading



artesian water



inflation



fossil pressure

The occurrence of overpressure as a consequence of sediment loading, outlined on the previous page and sketched in the first figure above, is probably the most common and certainly the most important cause of overpressures. It is typical of the major deltaic oil-producing areas of the world and is, moreover, the cause of the characteristic growth-fault-and-rollover tectonics of such areas. The latter as a result of the mechanical instability of the overpressured marine clays underlying the deltaic sediment masses.

Abnormally pressured, so-called artesian waters have been known for a long time and have been used gratefully for water supply purposes. Some oilfields produce from sands which have abnormally high pressures as a result of an artesian situation.

It was mentioned above (p. 158) that faults may act as channels for fluid flow. This may be the cause of high pressures occurring in sands, which would not normally be overpressured, as a result of leakage along a fault from an underlying overpressured reservoir; 'inflation pressure'.

'Fossil' overpressures may exist in a reservoir which is entirely sealed and thus may retain the pressure which it had originally. After uplift – and erosion of part of the overburden – such a reservoir will exhibit the pressure it had when at greater depth and thus appear to be overpressured.

Overpressures are a very dangerous phenomenon for the oil industry. In normal circumstances, the density of the drilling mud in the drilling well is maintained at such a level that the mud pressure at depth just exceeds the hydrostatic pressure at the same depth. Fluids from the formation then cannot enter the well-bore against the higher pressure of the drilling mud. If, however, a reservoir zone is drilled into, where the pressure is – unexpectedly – higher than would accord with the hydrostatic gradient, fluids can enter the well from the reservoir.

If this fluid is water, it will dilute the drilling mud and the resulting decreased density of the mud column will lead to high pressures at the well-head. If the reservoir fluid is oil or, even worse, gas, the dilution effect will be stronger and the resulting wellhead pressure even higher. The well-head equipment is designed to withstand such pressures and 'killing' the well will then not cause excessive difficulties. If, however, the equipment fails, oil or gas may flow out of the well uncontrolled and fires are a likely consequence.

The risk of such blow-outs requires elaborate and expensive precautions when drilling in areas where overpressures may occur; the depth where these overpressures will be encountered can usually not be predicted with accuracy.

F.8 REVIEW

The external geometry of the reservoir was depicted – as realistically as possible – in the tectonics work; the internal structure was analyzed and described with the help of sedimentology in the reservoir geology work; the composition of the reservoir fluids was examined; the distribution of the hydrocarbons over the complex of deformed rocks in the oilfield was recorded, analyzed, and perhaps to some extent understood.

Thus the geological, in a wide sense, picture of the field is now complete and in the following chapters attention is given to the application of this knowledge in the interests of rational exploitation of the oilfield.

The geological image of the field is ready for use, but this does not mean that it is a finished product. In the course of field development drilling, additional data become available and continuous – or at least periodical – revision of the geology is needed to ensure that the geological picture still meets the requirement of being 'the best possible'.

Chapter G

APPRAISAL DRILLING

G.1 PRINCIPLES

The life of an oilfield starts when an exploration well – drilled under the responsibility of the exploration department – has encountered a hydrocarbon-bearing formation of such thickness and apparent quality, that the possibility of a viable field being present has now become a probability.

At this stage the information available on the geology of the field is still meagre: a seismic picture, which at this stage is usually on the vague side, and the data from the one well drilled. In order to gather additional information, a number of wells normally has to be drilled; these wells are called appraisal wells (or reconnaissance wells).

The first question to be answered is, obviously, whether a sufficient quantity of hydrocarbons is present in the potential field to pay for the costs of developing and producing the field and to make a profit. Answering this question at this early stage is primarily a geological problem and the appraisal wells have to be sited in such a way that the maximum of useful geological information is obtained.

Once it is decided that the prospects of the field appear good enough to risk going into the development phase, the question of the optimum development plan immediately comes up. This question also has to be answered, as well as possible, on the basis of the information provided by the appraisal wells.

Appraisal drilling thus is a phase between exploration and field development. Consequently, both the exploration organization and the production geologist have to make their contribution in the planning and drilling of the appraisal wells. The former do so on the basis of the previously gained knowledge of the geology of the region in which the field lies. The production geologist contributes from his knowledge of the aims and policies of oilfield appraisal and development, and his experience in the geological aspects of these activities.

Appraisal is a very complicated activity and the details of the operations depend to a large extent on the unique geological characteristics of the particular case in hand. In consequence, it is not well possible to formulate general principles or rules which should be adhered to. In the following sections no more can be done than contribute some general guiding concepts.

G.2 INITIAL APPRAISAL

The fundamental question requiring an answer is: 'Is there enough oil (or gas) in the ground to pay for the development cost?'. So, an important element in the considerations is obviously going to be how high these development costs are likely to be.

In highly developed oil provinces in the USA it is not uncommon that the first well drilled on a 'prospect' is, at the same time: exploration well, appraisal well and first and last production well. In other words, in these cases it is economically justified to risk the cost of drilling a well to investigate a potential accumulation just large enough to pay for the one well. In such areas production facilities are usually already in existence close at hand – and perhaps not being used to full capacity – and therefore cheap; the drilling cost is then by far the dominant cost item.

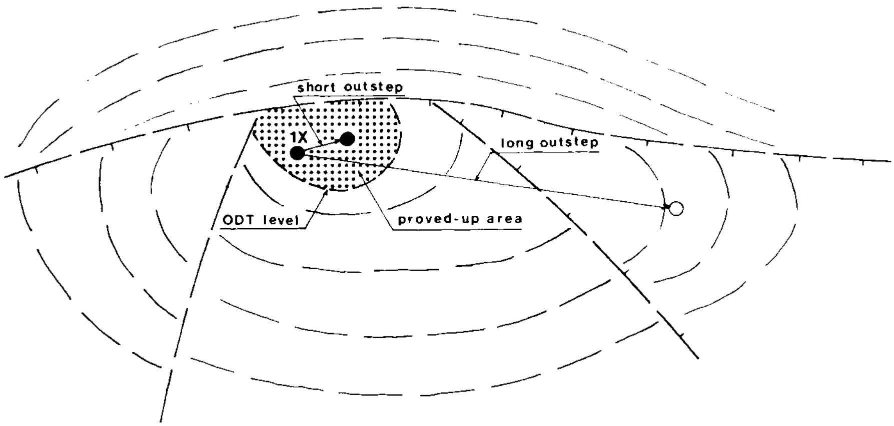
Elsewhere in the world the discovery is probably at a more remote location. Apart from the drilling costs, expenses have to be made for production facilities such as tanks, pipelines for evacuating the produced crude, possibly camp facilities, etc. The development costs are going to be higher and, therefore, also the amount of reserves needed to cover these costs.

In the offshore, development costs are much higher again. With present techniques most cases require the installation of one or more drilling/production platforms, a very important cost item, which moreover has to be committed at a very early stage. Other higher costs must be added: higher costs for individual development wells because of deviated drilling; appraisal wells have to be drilled before the platform has been installed and therefore cannot be produced at all (expendable wells) or have to be tied-back to the platform at high cost; construction of underwater pipelines for gathering and evacuation; probably provision of a floating storage system; etc.

In conclusion: the amount of reserves to be proved-up before development can justifiably be started will be quite different in different cases.

By and large the amount of reserves proved-up by a specific well, or group of wells, is directly related to the area reconnoitered by the well(s). The size of this area, in turn, is a function of the distance from the discovery well to the appraisal wells. This distance is colloquially known as the outstep length and it is the worst bone of contention in most discussions of appraisal plans.

OUTSTEP LENGTH



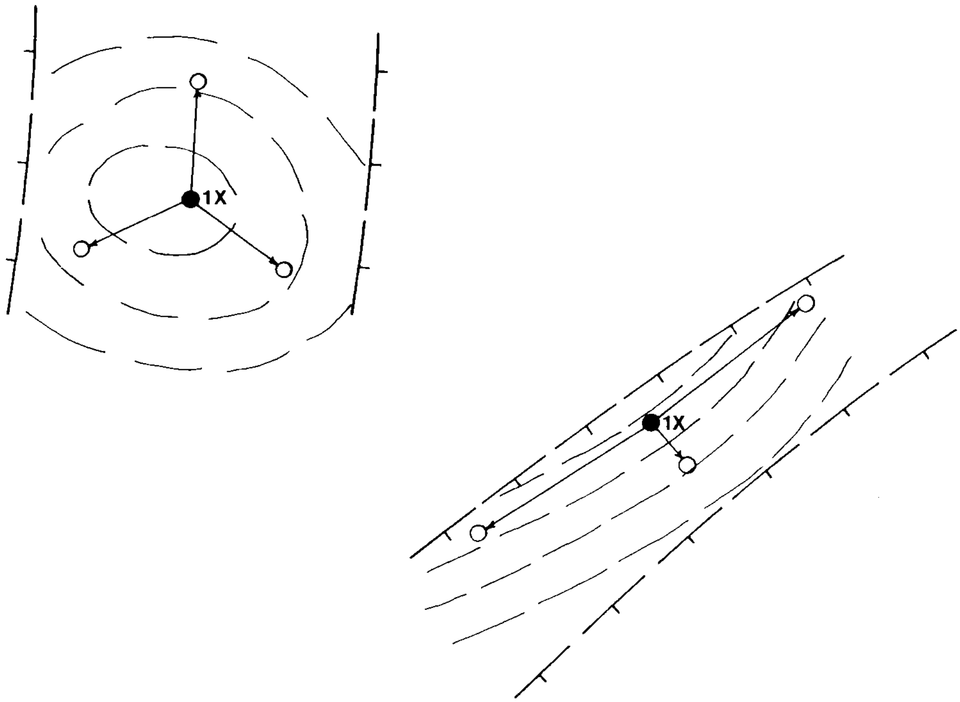
There is usually little disagreement on what constitutes too short an outstep. Assume that the short outstep shown in the sketch is drilled after the discovery well 1X. The data from the two wells define an oil-down-to level. With the help of the seismic picture an approximate intersection line of this ODT level with the top of the reservoir can be drawn; this is the outline of the proved-up area.

Now, the possibility exists that this ODT level is, in fact, also the oil/water contact, in which case the proved-up area contains all the oil that will be found on the structure (disregarding for the time being the possibilities on the other fault blocks). A fairly accurate estimate of this quantity can be made before the outstep is drilled. Should the quantity that can possibly be proved-up by the proposed well be so small that it could never cover even the lowest development cost estimated, there is no sense in drilling such a short outstep.

Much more difficult is the question of the maximum permissible outstep length. The natural tendency is to go to very long outsteps: the longer the outstep, the larger the proved-up area and the larger the field reserves proved-up; larger reserves allow installing larger facilities (larger diameter pipeline, two platforms instead of one); larger facilities bring economies of scale. Therefore, the longer outstep can make additional money, because savings on the development costs can be achieved.

However, as will be attempted to illustrate in the next section, the farther the outstep goes into the unknown, the greater are the geological uncertainties and, in consequence, the greater the risk of drilling a well that not only does not produce, but does not yield any useful information either.

OUTSTEP DIRECTION



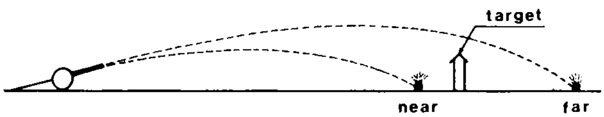
Apart from the length of the outsteps, the direction in which they are to be made also deserves careful consideration.

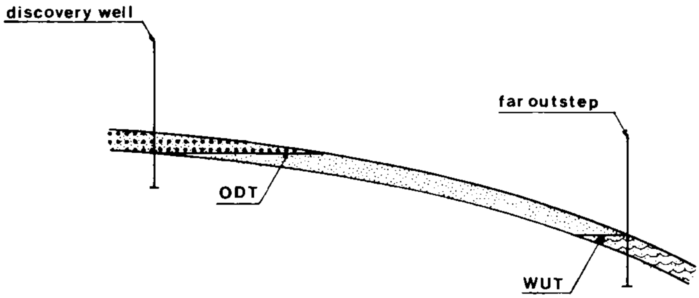
The cheapest answer would be an outstep in one single direction, but this will rarely be sufficient. The other extreme would be to ring the prospect with a series of closely spaced wells; this would be informative and probably fairly conclusive, but uneconomical. The proper policy is to find a suitable optimum between these two extremes.

Obviously, the choice must be determined mainly by the geological conditions of the prospect. In practice, if the prospect is more or less circular, three directions spaced more or less 120 degrees apart probably are the most effective answer. On an elongate structure, two opposite directions will probably be the best opening gambit, possibly followed by a short crosswise step.

G.3 INFORMATION VALUE

OWC DEFINITION





Appraisal wells are drilled primarily in order to obtain useful information and drilling wells costs money. Therefore, when drilling such a well is planned, it is imperative to consider carefully what the information value of the well is likely to be.

Information value is a somewhat vague notion, which may perhaps be illustrated with an example from another field of human activity. In artillery shooting, rangefinding shots are fired for the purpose of determining the correct elevation angle for the gun to hit the target. The position of the impact point, with respect to the target, is observed and the elevation angle corrected accordingly. In this operation the information value of the far shot is equal to that of the near shot, the former requiring less, the latter more elevation.

In appraisal drilling a comparable and very common objective is the definition of the OWC, in depth, but consequently also laterally. Assume that the discovery well has not encountered the OWC, in other words, it has drilled a full oil column. An appraisal well is to be drilled in order to find out where the OWC is located. There is a tendency amongst oilfield operators to decide in favour of a long outstep: if this finds the reservoir horizon fully water-bearing, it is argued, at least 'we will know'.

Nevertheless, as the figure illustrates, such a well does not add much to the solution of the problem: the vertical distance between the ODT level, defined by the discovery well, and the WUT level found in the outstep, is still large and the actual position of the OWC can still vary between these two extremes. This means that the OWC could still be situated very close to the discovery well (i.e. a short distance below the ODT level) and the outstep well has not really contributed significantly to the definition of the reserves of the field.

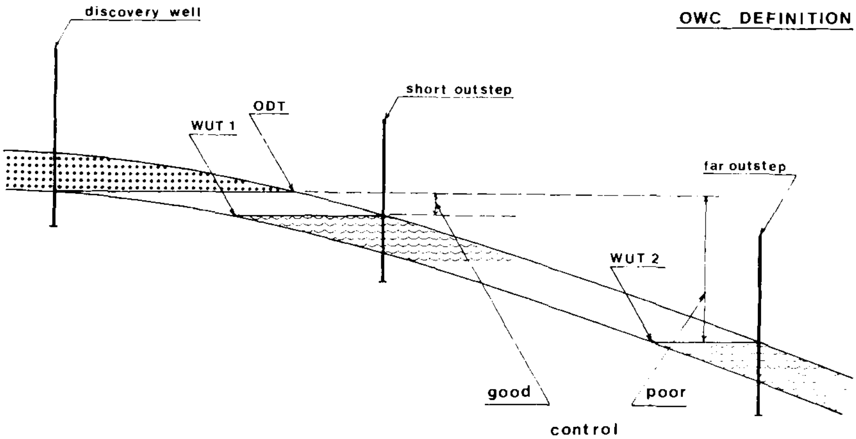
The definition of the amount of reserves in the field is the objective of appraisal drilling. This is important because the development plan of the field is to be based on this estimate and both too small and too large an estimated quantity are bad economically. If the field in fact is smaller than had been thought, the facilities will have been made too large and the excess capacity represents an unnecessary expenditure. Conversely, if the facilities are underdesigned, additional capacity will have to be constructed later, during the development of the field, and this will require extra-investments, which could have been avoided in many cases. As an example: it will be cheaper to develop a field with one larger platform than with two smaller ones.

From this point of view it is possible to express the information value of an appraisal well in monetary terms: the information obtained should be such that the development plan can be made more realistic and the value of the information equals the amount of investment that can be saved in consequence.

Another important financial consideration is that a well which finds only water cannot be produced; the drilling cost of such a well then has to be covered exclusively by the information obtained, i.e. by the savings which can be achieved in the field development. On the other hand, if the well had found the reservoir horizon oil-bearing, which is much more likely to be the case if the outstep was shorter, it would pay for itself out of production and the information value would become a bonus over and above the value of the oil produced.

The practical implications of these considerations in planning appraisal drilling will, it is hoped, be elucidated further in the following sections where various appraisal problems will be discussed.

G.4 GEOLOGICAL CONTROL



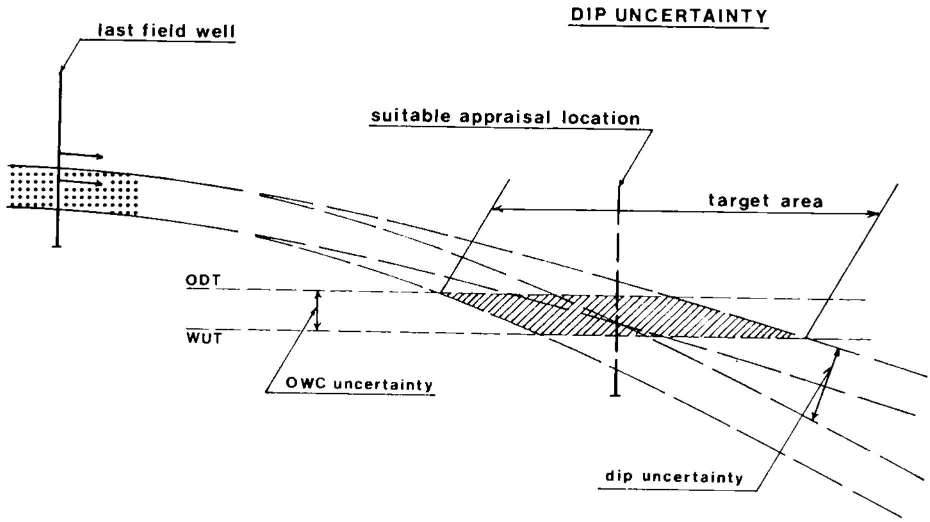
'Geological control' is another, admittedly rather poorly defined, but nevertheless useful, working concept in appraisal drilling. It might be described as a, more or less subjective, measure of the accuracy with which the geological situation in a specific area can be described; for instance, in a part of a developing oilfield. The quality of the control evidently depends on the complexity of the geological conditions and on the amount of geological information available.

Geological control by means of wells has some similarity to street lighting: around each lamp there is an area of good visibility; the visibility diminishes with distance from the lamp and, if the lamps are spaced far apart, there will be stretches of poor light and poor visibility in between. Similarly, each well 'lights up' the geology of the area around it. The radius of the control area depends mainly on the complexity of the geological conditions and evidently control improves with the density of the wells.

The concept can be illustrated with the problem of OWC definition. The far outstep leaves a large information gap between the ODT of the discovery well and its own WUT: the degree of control achieved is poor.

A better solution is generally to plan the outstep such that it will reach the top of the reservoir a short distance below the known ODT level. There are then three possible outcomes. If the well finds the reservoir section fully wet, as shown in the figure, at least it gives very good control on the OWC depth. It may also find the OWC in the drilled section, which solves the problem completely. Should it find a fully oil-bearing section, a further outstep on the same principle is indicated.

It may be objected that this repeated outstepping is a laborious process and may end up by showing that the OWC is, after all, very close to where the far outstep would have been. This is indeed possible, but all the wells drilled would be producers. Moreover, if the far outstep does not provide good control, it is likely that at least one further appraisal well will have to be drilled closer to the discovery and the far outstep has then been drilled in vain.



A common source of uncertainty is the estimation of the structural dip, away from control points, i.e. usually wells with dipmeter information.

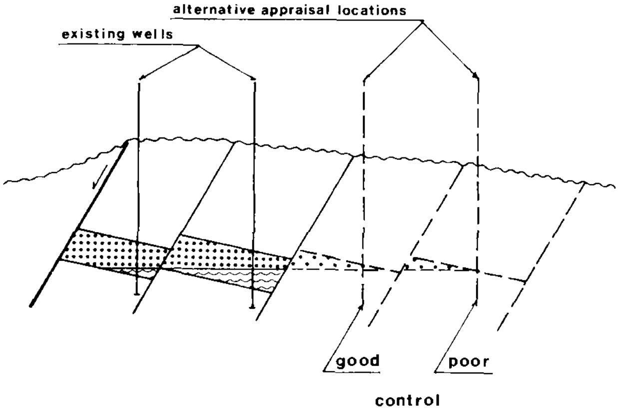
In the figure it is assumed that the dip some distance away from the last field well can vary between 15 and 25 degrees, a possible range in normal conditions. Also, it was assumed that it is known, from data outside the plane of the section, that the OWC depth can vary over a certain interval.

The two uncertainties combine to produce a considerable lateral range over which the position of the OWC can vary.

In planning the location for the next appraisal well it is good policy to actually construct a section such as the one shown above, in which the extremes of the likely ranges of variability are shown. The most favourable position for the appraisal well is presumably in the middle of the target range.

The figure shows that in the most unfavourable (the pessimistic) case, the well will find a fully wet section and thus be unsuccessful in defining the OWC. At the other extreme – lowest dip and deepest OWC – the well will drill a fully oil-bearing section and also fail to define the OWC.

However, these failures will occur only at the extreme ends of the probability distribution and the chances are high that the section will be found partially oil-bearing, in which case the OWC also has been defined, of course. In that case the well has achieved its objective and is a producer as well.



The situation becomes more complicated in cases where faulting plays a major part. In an – admittedly simplistic but not at all impossible – illustrative example shown above, the choice between a far and a short outstep is again presented.

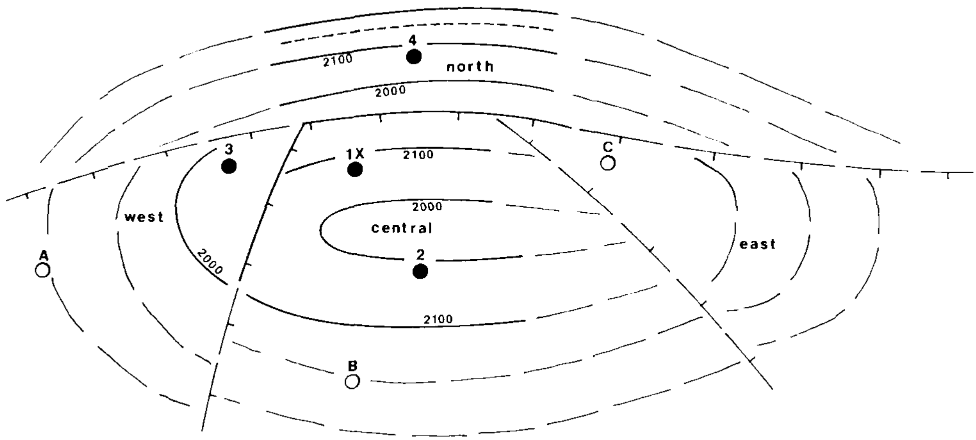
The far outstep is likely to prove to be located on the far side of two faults, with respect to the last previously drilled well. A well in such a position will of course yield a certain amount of information regarding the conditions in the fault block in which it is situated. However, no matter what its result is – oil, oil-and-water or water only – it will not provide certainty on the structural and accumulation conditions in the intermediate fault block. Even if the far outstep should find the same OWC as that in the existing wells, which would allow the assumption that the OWC is also the same in the in-between block, it is still not certain that the structural situation in this block is such that the reservoir section would be above the OWC.

In other words, the control provided by the far outstep is again unsatisfactory and a shorter step would be more informative. Such a shorter step is likely to be separated from the fault block previously penetrated by only one fault and thus would provide better control. Even if two faults would have been skipped over, the fault sliver between these two faults would be so small as to make at best an insignificant contribution to the reserves.

It has been tried to show with these examples that, in general, the risk of drilling an uninformative well increases with distance from the last previously drilled well. In other words, the information value of an outstep well may increase initially with outstep length, because the area reconnoitered becomes larger. But beyond a certain point it is likely that the additional control provided decreases sharply and that the information gained is insufficient to cover the expense of drilling the well.

As an experienced petroleum engineer, not a geologist, once phrased the rule of the game: 'Do not outstep so far, that later on you will have to come back in between'.

G.5 SECOND ROUND



The map symbolizes conditions (comp.p. 165) after three appraisal wells have been drilled. Well 2 has further defined conditions in the crestal area of the central block; well 3 has confirmed that the west block is oil-bearing and confirmed the existence of the cross fault; well 4 has confirmed the main longitudinal fault, defined the structural position of the north block and established the OWC on that block (at ca.2150 m). Most important: all three wells are producers.

It is possible that enough potential production has now been proved-up to justify the decision to start development of the field. However, several important questions regarding the configuration of the field still remain unanswered: depth of OWC on west and central blocks; structural level and accumulation conditions on the east block. It may be decided to go ahead with development and find the answers to these questions in the course of further drilling. But it may be wiser to drill a number of appraisal locations for the specific purpose of clearing-up the main remaining uncertainties; the decision whether or not further appraisal is justified will depend on the savings that can be achieved by more efficient planning of the development drilling campaign.

On the map three appraisal locations for a 'second round' are indicated. Location A is intended to investigate the position of the OWC on the west block; loc.B is to do the same for the central block; C will investigate the east block and define the position of the eastern cross fault.

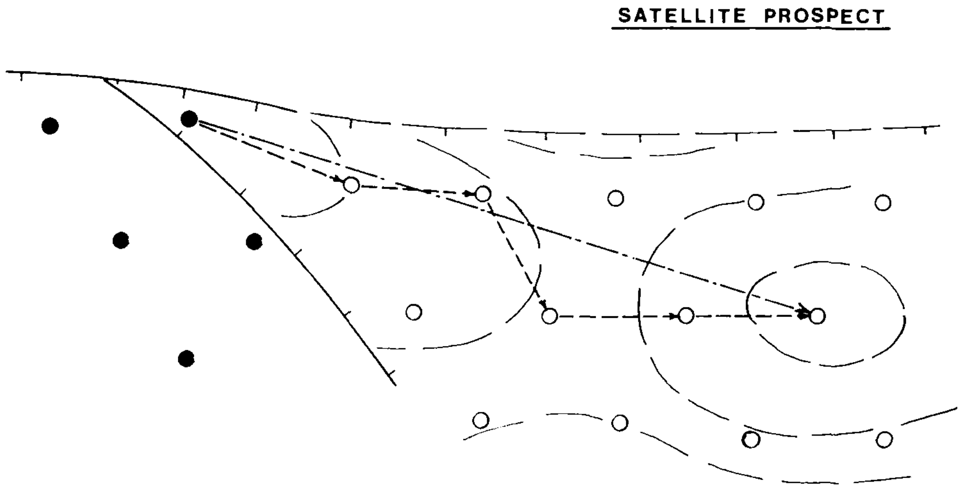
In many practical cases the exact siting of an appraisal location and even the decision whether or not it will be drilled may be dependent on the results of other wells to be drilled first. For instance in the case sketched above, the choice of the definite site for location A is somewhat dependent on the result at B. The most likely supposition regarding the depth of the OWC on the two blocks concerned is that it will be the same. So, if (the well at) location B should find a high OWC, say at 2100, it would be advisable to move location C higher up-structure to avoid drilling a uninformative well of the kind sketched on p. 167. If, on the other hand, the OWC in the central block proves to be below, say, 2300, loc.A should be moved down-structure to give it a good chance of penetrating the OWC.

In fact, even the drilling itself of location A may be considered to be dependent on the results of B. If the OWC on the central block is very high – and still on the assumption that the OWC's of west and central blocks are identical – it may be decided that the likely reserves of the west block are so small that well 3 is sufficient to drain this volume and the drilling of further wells in this block may be omitted.

As, for obvious reasons of efficiency, it is generally sensible to plan the drilling programme for a good number of locations ahead, this concept of 'dependent locations' is of great practical importance. The drilling programme will distinguish between 'firm' and dependent locations, and the latter will be included only tentatively.

In this connection, it is useful to emphasize that it is undesirable to identify locations for future drilling by sequential numbers. Even the letter code employed in the foregoing may lead to confusion: the tendency will be to expect that location B will be drilled after location A. But as A is dependent on B, the sequence should in actuality be the other way around. To avoid such confusion it is preferable to design some system of location nomenclature which does not carry sequential connotations (ref.p. 185).

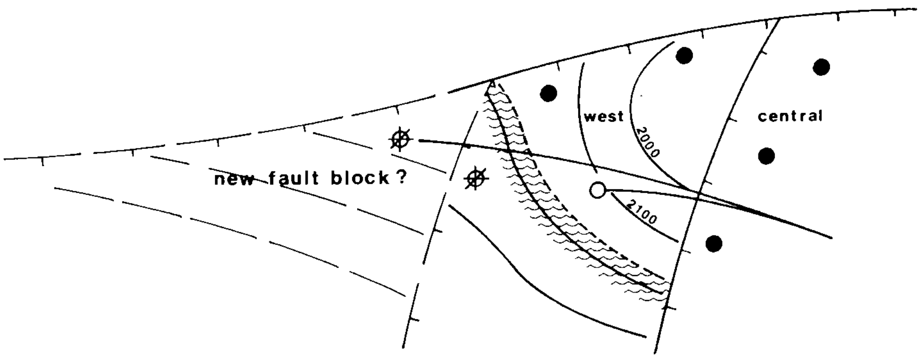
G.6 LATER PHASES



It is not uncommon that somehow – usually by seismic – the existence is indicated of a prospect at such a distance from a developing field, that it might eventually prove to be part of the same field; in other words, that there would prove to be a continuous, or at least nearly continuous, accumulation of hydrocarbons from the field to the prospect.

It may be assumed that such a 'satellite prospect' will eventually be reached by the process of gradually 'outstepping from known oil'. Development wells are normally – or should be – drilled on a more or less regular grid and the development drilling campaign proceeds step by step from grid location to grid location (ref.Chapter H). If a satellite prospect exists, should one await the time when the prospect is reached 'automatically' by the gradual outstepping process? Or should one proceed immediately to the prospect in one long step, without awaiting the additional geological control which the field development will provide, with the considerable risk of drilling a useless dry hole?

To answer these questions, economics should again be considered: long delays before known reserves are developed – long 'lead times' – are likely to result in losses of potential returns on investments already made, e.g. exploration costs. Moreover, if proof of additional reserves is obtained early, economies of scale may be realizable. Perhaps it is not unreasonable to adopt as a practical rule that the drilling of an immediate long outstep is preferable, if otherwise the delay in starting the development of the new prospect would run into a matter of several years.

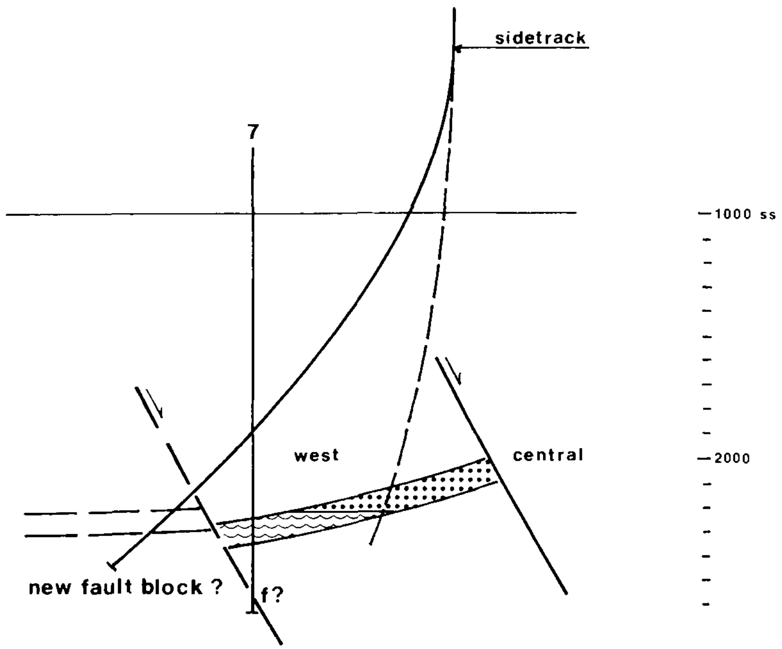


Each developing field eventually reaches the mature stage, when the development of the prospective field area is nearing completion and the time can be foreseen when the drilling activity in the known field will come to an end. It is then the time to carry out a thorough survey of the field, in order to define any possible remaining prospects, in the field area proper or its immediate vicinity; such studies are known as field reviews. It is desirable that remaining prospects are recognized before the drilling string moves out of the field, in order to avoid mobilization and other expenses which will be incurred if a drilling outfit has to be brought back into the field.

Often such prospects exist in previously unknown fault blocks, adjacent to the main drilled-up field area. For instance, in the figure above, well nr 7 – the 'wet well which defined the OWC in the west block (ref.pp. 172 and 186) – on careful examination of the data suggested the possible existence of a further cross fault, similar to the fault separating the west from the central block. Seismic has indicated a general southerly dip farther to the west, i.e. a dip away from the main boundary fault. It is possible that this south-dipping block, limited by the boundary fault and the supposed cross fault, creates a trapping situation or 'closure'.

For investigating whether this suspected new fault block does indeed exist and contains oil, a special appraisal well will have to be drilled. It is obvious that the cost of drilling such an appraisal well will have to be defrayed from the proceeds of the oil to be recovered from this fault block. Starting from the assumed structural configuration and postulating a likely position for the OWC, a fairly accurate estimate can be made of the amount of oil which could be present in the block. Only if this quantity is more than sufficient to pay for, at least, the one appraisal well, should such a well be drilled.

DROPPING OFF



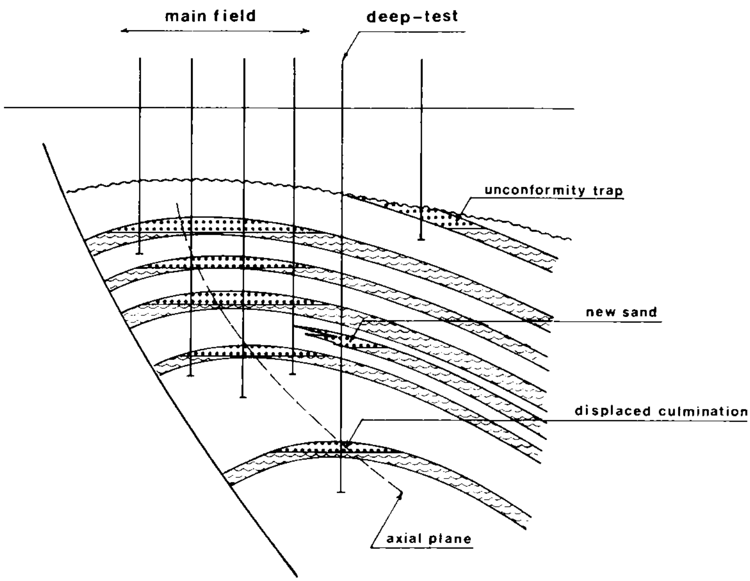
When a doubtful prospect on a suspected new fault block is to be investigated, as discussed on the preceding page, it may be possible to reduce the money put at risk for drilling a special appraisal well by applying what is known as the dropping-off trick. This technique can be used frequently in offshore fields where the majority of field wells are deviated from a platform.

It was assumed that well 7 found indications of a fault. To the west of this fault a fault block might exist with closure against the main boundary fault. An appraisal well from the platform is drilled deviated towards a target in this block. If there is indeed oil in the new block, the well will be completed as a producer.

If no producible oil is found, the well will be plugged back and the lower part of the hole effectively abandoned. The plug back depth has been chosen so that the well can conveniently be sidetracked and a new, less deviated hole can be drilled to a target in the west fault block; the operation is shown in map view on the previous page.

In the west block two producers have already been drilled, but there is need for another drainage point and this is now provided by the dropped off hole. Thus the cost of appraising the new block is reduced to that of drilling the lower part of the original hole and the plug back and sidetrack operations; the remaining costs are covered by the oil produced from the sidetracked hole.

SUBSIDIARY TRAPS



Subsidiary prospects in a field are, of course, not confined to new fault blocks. In the figure some possibilities are sketched: an unconformity trap outside the area of the main field; a previously unknown sand intercalated between sands already in exploitation; a deeper culmination, displaced laterally with respect to the culminations of shallower layers in a fold with inclined axial plane.

The latter prospect was discovered by a so-called deeptest. In the earlier years of the oil industry, the depth to which the exploitation of a field proceeded was often limited by the depth limitations of the drilling rigs. Consequently, a shallow producing horizon was often fully drilled-up before improved technology permitted investigation of deeper horizons. A well drilled for this purpose was called a deeptest.

In the present time it is usually more advantageous, in the interest of more efficient development planning, to drill, early in the life of the field, to such a depth that all potentially productive horizons have been penetrated. Ideally, the first well, or one of the first round of wells to be drilled in the field, should reach what is sometimes called 'economic basement'. This term refers to the stratigraphic horizon below which no further accumulations are likely to be found. In many cases this corresponds to what is geologically named basement, usually a complex of highly deformed, igneous and metamorphic rocks. In other cases there may be a level below which the porosity of the sediments has been decreased so much, by compaction and diagenesis, that no economic production can be expected from rocks below this depth and deeper investigation becomes unjustified. There is perhaps a certain amount of risk in such a conclusion: it may not be too certain that no freak porosity development exists at greater depth!

G.7 REVIEW

In this chapter there has been frequent mention of such concepts as: uncertainty, risk, chance, etc. This is to stress that appraisal drilling is a matter of 'playing the probabilities', of balancing risk against potential gain.

The risk is, mainly, that of drilling an unproductive well, a dry hole. A well that does not produce oil or gas, constitutes a loss of the drilling cost and possible additional costs. The only possible gain to offset this loss lies in the geological information which the well may provide; financially this gain can be expressed as the amount of money which could be saved in the further development of the field on the basis of the information obtained from the well.

The return on investment is very much higher if the appraisal well turns out to be a producer. A producing well pays for its own drilling cost; if this were not the case, the field's development would not be a viable operation. Hence, the geological information obtained from a productive well becomes a bonus, over and above the proceeds from the production. Moreover, the information yielded by a well which penetrates the oil column is usually more than that obtained from a dry hole.

In the balancing of risk against potential gain, therefore, the scales are a priori weighted against the dry hole and in favour of a careful approach which is likely to result in a producing well.

Because of the complexity and uniqueness of the geological conditions in most oilfields and the paucity of the geological information normally available in the appraisal stage, the planning of field appraisal is to a considerable extent based on subjective judgement. Subjective judgment, in turn, is helped greatly by experience. Of all the members of the E&P departments, the production geologist is most closely involved in the intricacies of the game of playing the probabilities and, therefore, most likely to have gained valuable experience. Therefore, in the planning of appraisal drilling, the production geologist should have the decisive voice.

Chapter H

DEVELOPMENT DRILLING

H.1 PRINCIPLES

The purpose of the appraisal drilling campaign was to provide information regarding the size of the potential oilfield and sufficient information to serve as a basis for the decision to go into the development of the field.

This decision is obviously a management decision, in which all members of the petroleum engineering department contribute their advice, each from the point of view of his discipline. The geological information and its evaluation are still important – if not the most important – elements in the considerations. It is not uncommon that the production geologist is the last member of the team to agree that the information obtained is indeed sufficient for a positive decision to start the development of the field.

For, despite the amount of information obtained, there is always still a large margin of uncertainty left about the size and quality – and therefore the economics – of the field. The decision to develop is always a 'decision under uncertainty'.

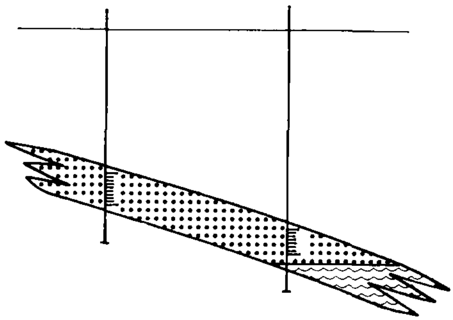
Once the decision has been taken, a development plan has to be made up. This plan basically consists, in the first place, of a forecast of the number of development wells required to achieve optimum recovery of the reserves present in the field. Secondly, the distribution of the drainage points over the field area has to be at least outlined, so as to achieve the optimum drainage pattern for the production conditions imposed by the specific characteristics of the field.

On the basis of this plan the development drilling campaign starts. During this phase the knowledge of the geology of the field – and of the other relevant characteristics – increases. In most cases this increased knowledge shows that the conditions in the field are appreciably different from what was originally assumed. In consequence, the details of the development plan have to be modified in accordance with the new knowledge: development planning is a continuous process that goes on until the field is drilled-up.

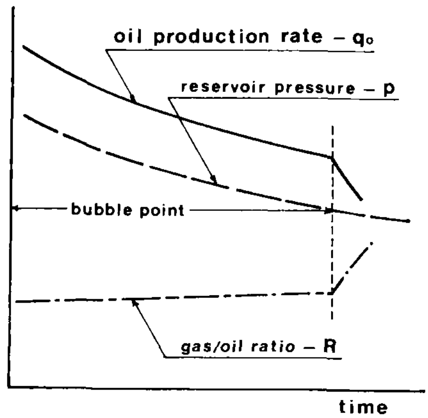
H.2 RESERVOIR BEHAVIOUR

DEPLETION

DISSOLVED GAS DRIVE



reservoir : **closed**
under-saturated



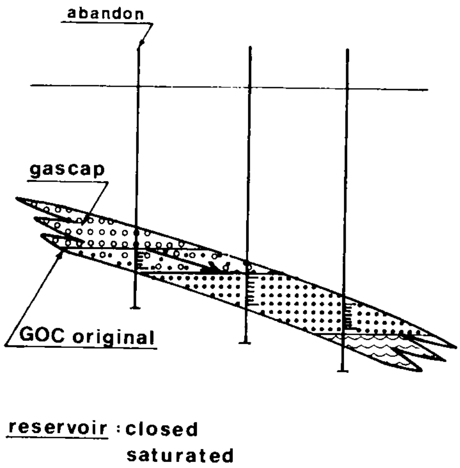
When oil is produced, fluids are withdrawn from the reservoir; this results in changes of pressure in the reservoir and in movements of fluids through the reservoir. Different reservoirs tend to show differences in the variations with time of reservoir pressure, oil production rate, proportion of gas and water produced, etc. These variations are referred to, collectively, as: reservoir behaviour. The sketches on this and the following pages attempt to illustrate the more common types of reservoir behaviour – admittedly in a highly schematic manner.

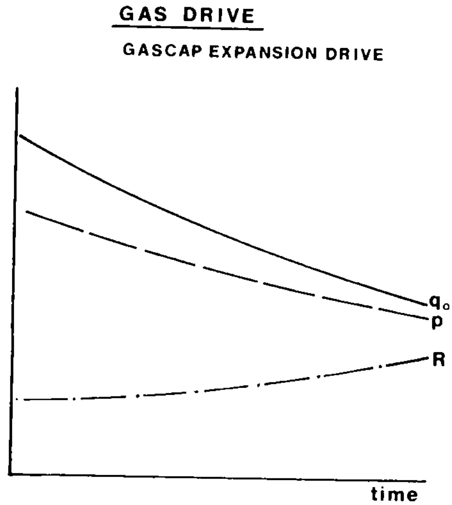
The type of reservoir behaviour that will occur depends very largely on the conditions originally prevailing in the reservoir.

The first case is that of a closed reservoir, i.e. one into which no fluids from outside can penetrate. The hydrocarbons in the reservoir are undersaturated, i.e. no free gas exists at reservoir conditions (comp. Section E.4).

As oil is extracted from such a reservoir, and not replaced by other fluids, the pressure in the reservoir drops gradually and the oil production rate declines accordingly. The gas/oil ratio (GOR, the common measure of gas production) often increases slightly at the same time. After some time the pressure would drop to the level of the bubble point. When this is the case, free gas will develop in the reservoir in the form of bubbles in the oil. This results in a sudden increase of the volume of gas produced from the wells and concomitant abrupt reduction in the oil production rate.

This is naturally a undesirable effect: the remaining reserves will be recovered, if at all, at a much slower and less profitable rate. This effect can probably be prevented by pressure maintenance by water or gas injection (ref. Section H.4).



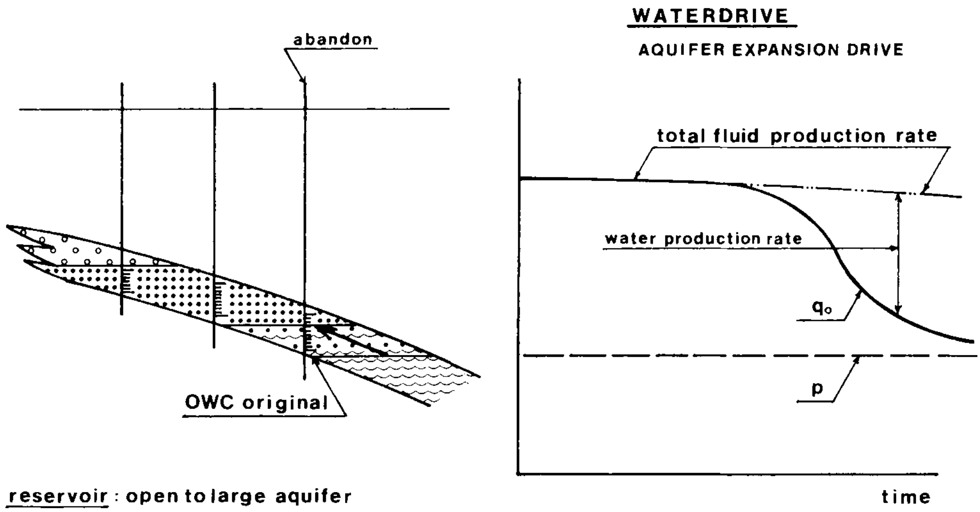


In the case sketched above, the reservoir is also 'closed', but the content is saturated, in other words free gas exists in the reservoir at the original, virgin reservoir pressure. This gas is present in the form of a gascap overlying the oil column, the two being separated by the gas/oil contact.

When oil is produced, the volume of liquids in the reservoir is reduced and the pressure decreases. In cases where oil production is the objective, the wells are completed in such a manner that no perforations are made in the gascap; consequently no free gas is produced. In accordance with the pressure decline the gascap will expand and consequently the GOC is forced lower into the reservoir.

Eventually the moving GOC will reach the level of the perforations in those wells which are in a high structural position. As it is necessary to keep the gas production as low as possible, such wells will have to be 'shut-in', i.e. arrangements made to stop the production from the well; this leads to a reduction in the number of drainage points available and thus to a reduction in the field production rate.

In this case, as well as in the former, the detrimental effects of the pressure decline, especially the loss of drainage points caused by gascap expansion, can be combatted by pressure maintenance.



In the case of water drive, the reservoir is 'open', i.e. connected with a large volume of water-bearing reservoir rock. A volume so large that the volume of oil-bearing reservoir is small in comparison to the water-bearing portion or 'aquifer'. Obviously the volume of the extracted oil is negligible with respect to the total fluid volume in the reservoir.

Consequently, when oil is removed the pressure in the reservoir will not decrease: the large communicating volume of water will expand to make up for the fluid volume lost to the reservoir. This, in turn, results in a fluid production that declines only slightly as time goes on.

But, in a similar way as the gascap expands by lowering the GOC, the aquifer water expands by pushing up the oil-water contact. As a result, the lowermost wells in the reservoir will, after some time, be reached by the free-moving formation water and will start to produce appreciable volumes of water instead of oil: the edge-water has 'broken through' into the well and as a result the watercut increases. This also means that the total fluid production of the field may stay approximately the same, but part of this production is water and the oil production rate, therefore, shall decline as the water production rate of the field (the field watercut) increases.

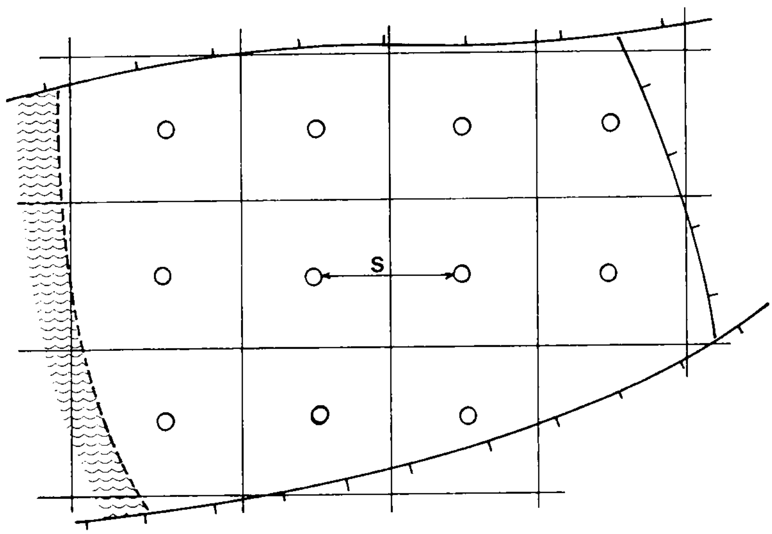
All this applies only if the water drive is 100% effective. In practice, it is not uncommon that not all the extracted oil volume is replaced immediately by water, because of insufficient permeability or too small a volume of aquifer. In such cases the reservoir pressure and the field production rate will not stay constant but will decline appreciably with time and the gascap, if present, will expand. It may be attractive in such cases to supplement the natural water drive artificially by injecting water.

The three cases presented are all cases of pure drive types. In practice, mixed types are likely to occur, as for instance the case of the not 100% effective water drive mentioned in the last paragraph. Herein lies most of the raison d'être of reservoir engineering: careful measurements of the volumes of oil, gas and water produced and of the pressure in the reservoir (bottom hole pressure or BHP) are continuously carried out as long as the field is in production; these form the input for intricate reservoir engineering calculations, nowadays often carried out by means of numerical simulation models worked out by computer.

In connection with the planning of the field development the type of reservoir behaviour prevailing in the field is obviously of high importance, ref. for instance the possibilities of structurally high wells gassing out by gascap expansion and low wells becoming less then fully effective because of water encroachment. It is therefore of great interest that an accurate forecast of the reservoir behaviour is built into the development plans as early as possible. Unfortunately, the production and pressure information available in the early stages of field development, when the foundations of the development plan have to be laid, are often insufficient for a reliable forecast. It is then imperative to design the development plan in such a way that the optimum of flexibility is left in the distribution of the field wells and in the method of completion of the wells.

H.3 INITIAL DEVELOPMENT PLAN

QUICK-LOOK DEVELOPMENT PLAN



A proper development plan must be based, of course, on proper reservoir engineering calculations, often by means of computerized numerical models. However, the data required for such calculations are probably not yet available in the early stages of field development and, moreover, such calculations take time.

In consequence, there is often call for at least a 'quick-look' development plan from which a 'ballpark' figure for the number of wells to be drilled can be obtained:

R = ultimate recovery for the field = estimated total quantity of oil to be produced from the field.

r = ultimate recovery per well, estimated from the initial production rate and an assumed decline rate.

$R/r = N$ = the number of drainage points required.

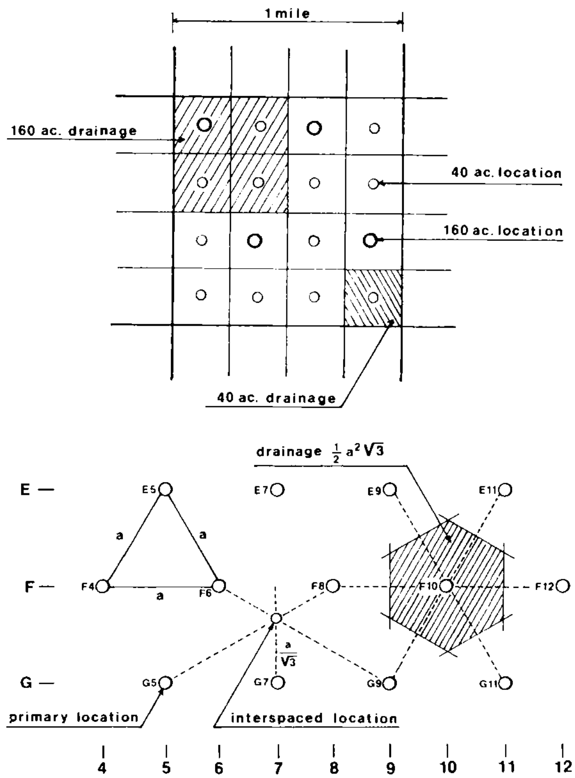
A very tentative sketch of the arrangement of the drainage points over the field area is also useful; in general, a regular distribution over the area is the most likely assumption:

A = productive area of field.

$A/n = a$ = drainage area per well.

$\sqrt{a} = s$ = well spacing on square pattern.

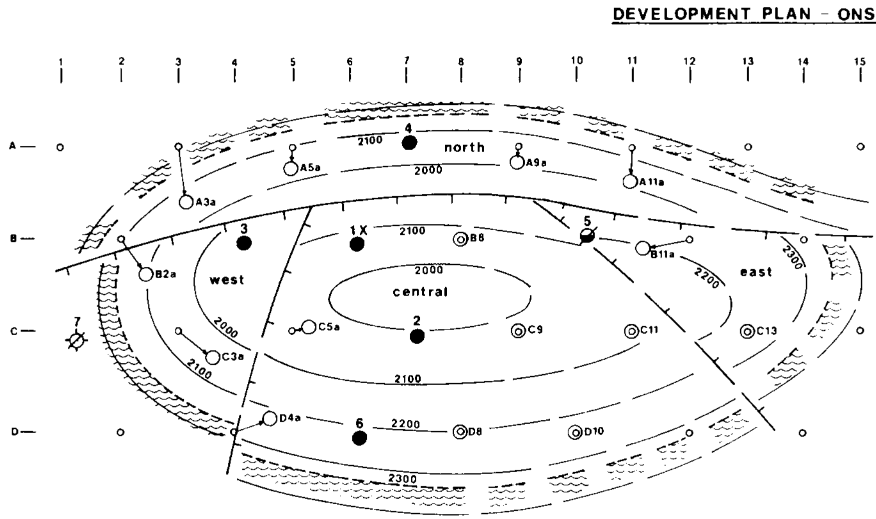
LOCATION GRIDS



Where several producing wells are to be drilled into a reservoir of fairly uniform quality, it is obviously desirable to have the wells arranged in a fairly regular pattern. Each well will then drain approximately the same volume of reservoir. On the other hand, wells must be located in optimum position with respect to the geological structure. In order to avoid that the well pattern becomes uneven, it is useful to lay out at the start a regular grid of potential locations over the field area. This grid can then be used as a guideline in the selection of the actual drilling locations.

In oil-producing areas of the USA, use is often made of the existing grid of mile-square sections. Within one section 16 locations are then arranged in a square pattern. Each location has a theoretical drainage area of 40 acres. In many cases the operator will start by drilling one well per quarter-section, i.e. on 160-acre spacing; later these may be 'interspaced' to 80 acres or 40 acres, where and when desirable.

In other areas a system may be applied using a triangular pattern; the spacing of the wells has to be chosen in conformance with the reservoir properties. If the primary grid provides insufficient drainage points it can conveniently be interspaced 'centre-of-gravity' ($0.58 \times a$, triangular spacing). A simple map index system will provide a convenient nomenclature for the locations or 'targets'.



To continue the story from Section G.5: second round appraisal well 5 has proved oil on the east block, but found part of the productive interval cut out by a fault; the seismic fault has been moved eastward accordingly. Well 6 has defined the OWC on the central block; well nr. 7 proved to be a dry hole as a result of an unexpectedly high OWC on the west block.

A triangular location grid, with nomenclature system, has been laid out and the development locations have been tentatively chosen. On the north block the four locations chosen are off-grid, moved southward to be farther away from the OWC on the rather narrow fault block. Off-grid locations are identified by the suffix 'a' after the original location number.

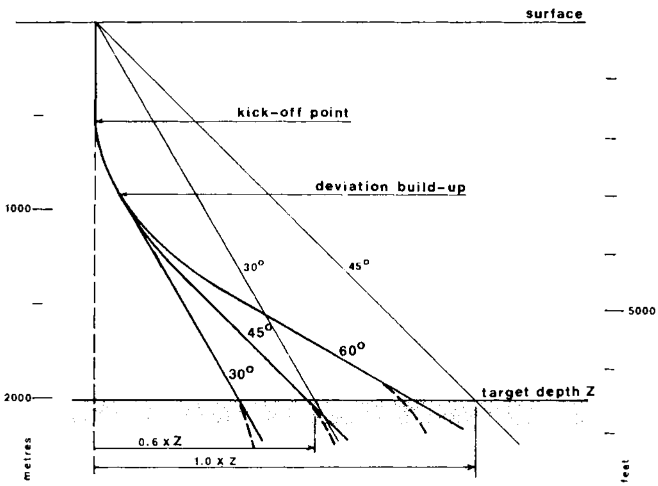
On the central block the original grid locations have mostly been retained, except for two locations adjusted away from the boundary fault with the west block.

On the west block the two remaining grid locations have been moved to form a regular pattern.

Conditions on the east block are not yet well established, because the OWC has not been defined. It has been assumed, for the time being, that the OWC is at the same depth as in the central block. Two locations have been selected, but it is not unlikely that another drainage point will eventually be required.

The sequence in which the locations will be drilled is relatively unimportant. Apart from optimization considerations, such as shortest rig moves, the main arguments for selecting the drilling sequence will be derived from the desired production build-up. It seems likely that the central block will be drilled-up first; followed possibly by the east block in order to obtain additional information regarding the reserves in this block.

DEVIATION REACH



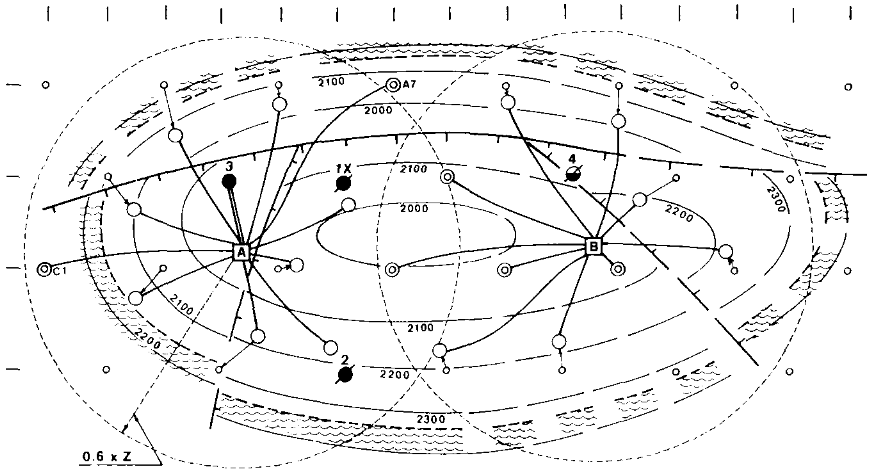
In onshore conditions one is generally fairly free to select a surface drilling site for a well, such that the subsurface objective can be reached with a vertical well. In the offshore, however, technical conditions impose severe constraints:

- with present technology, development wells generally have to be drilled from a platform by deviating towards the subsurface target; the 'reach', or maximum distance from the platform which can be reached, is restricted by technical conditions.
- the number of 'slots' on the platform, i.e. the number of wells it can support, is defined by the design of the platform.

The reach is determined by the drilling procedure. The uppermost portion of the well generally has to be drilled vertically. From the kick-off point the deviation must be built-up gradually to avoid sharp bends (doglegs) in the hole. There is a maximum to the deviation angle which can be attained; 60 degrees being well within practical possibilities at present. For purposes of development planning, drilling experts have to be consulted for realistic figures of attainable reach, taking into account target depth and the nature of the formation to be drilled through.

The figure is based on reasonable assumptions: kick-off at 500 m (1500 ft) and build-up of about 6 degrees per 100 m (2 degrees per 100 ft). With a maximum angle of 60 degrees, the target depth of 2000 m is reached at a distance of 1700 m from the surface (platform)site. In this case therefore the reach is somewhat less than the target depth; with greater target depth the reach may exceed the target depth. It is convenient for quick-look purposes to keep in mind that the reach in most practical cases is of the same order as the target depth (45 degrees overall deviation from surface).

DEVELOPMENT PLAN – OFFSHORE



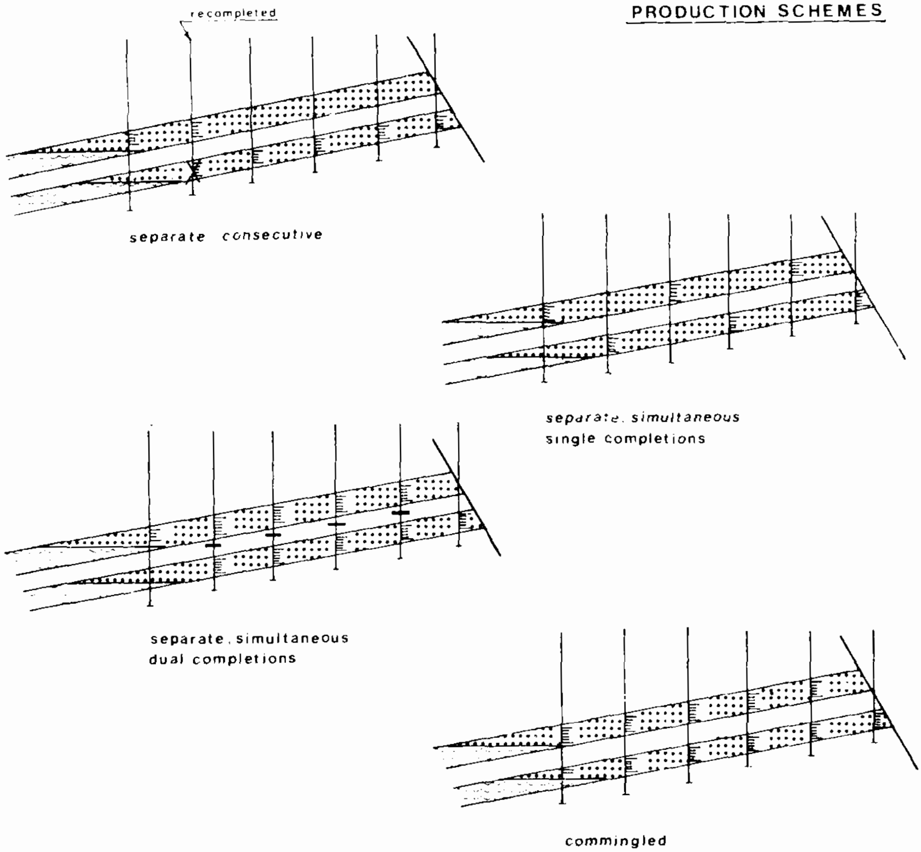
The imaginary offshore development plan starts from a situation somewhat different from the onshore plan (p. 186), mainly because longer first-round outsteps have been assumed. Long outstep 2 has defined the OWC on the central block but was abandoned: in view of the presumably short productive life so close to the OWC, it was considered unattractive to go to the expense of tying-in the well to the eventual platform. Well 3 proved oil in the west block and is to be tied-back to the platform. Well 4 proved oil on the east block, but found the productive section largely faulted out and was abandoned.

The figure shows that all the probably required targets can be reached from two platforms, with maximum deviations of 30 degrees from surface. Schematically each platform has to support ten wells; in order to allow for contingencies the platforms will be built with twelve slots.

The choice of the sequence of drilling is much less free than in the onshore case. Two far outsteps are required immediately to provide information: target A7 to investigate the north block and C1 for OWC definition on the west block. These will be drilled as soon as platform A is ready. In deciding the further drilling sequence, the arrangement of the slots on the platform will play a part, besides the production considerations mentioned for the onshore case. Construction of platform B will take some time, so that drilling of the wells from this platform will start after part of the targets of platform A already have been drilled.

It must be mentioned that techniques for underwater completion and production of single wells is rapidly being developed and becoming economically acceptable. When this reaches the stage that platforms are no longer necessary, the offshore development planning will become more like that for onshore fields.

PRODUCTION SCHEMES



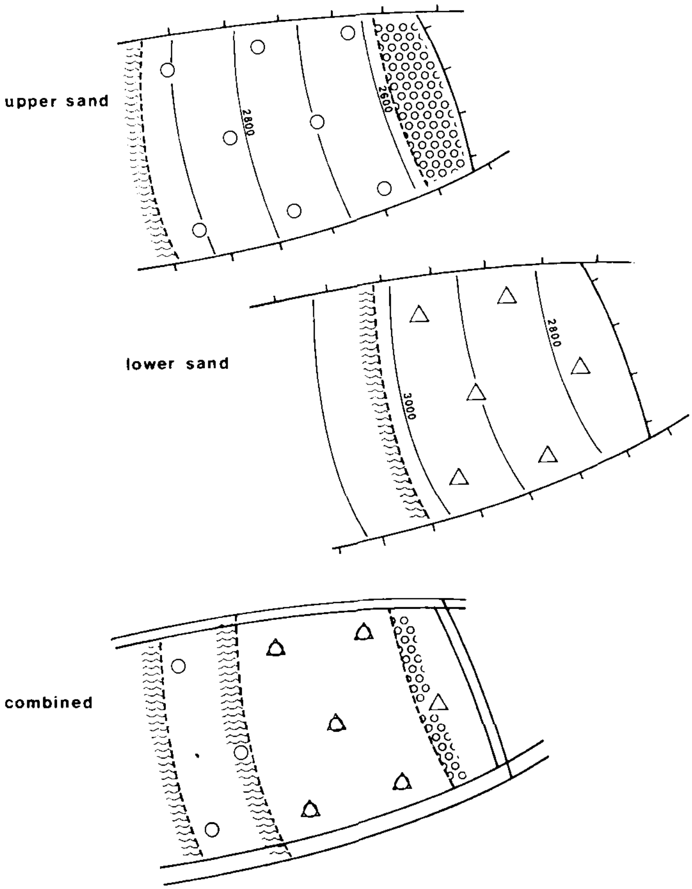
In many fields two or more productive reservoir zones are present one above the other. In preparation for the development plan, the question has to be answered how the zones are to be produced. The various possibilities for the case of two reservoirs are shown above and it will be clear that the choice of production scheme will influence the arrangement of the wells in the field.

The simplest solution is to produce the lower zone first, until this is no longer economically justified, at which time the wells will be re-completed on the higher zone. In the figure it has been assumed that the structurally lowest producer on the lower sand has already gone to water and been recompleted on the upper zone.

In the second case separate wells are drilled for each zone, so that both zones can be produced simultaneously, which is economically more attractive in most cases. Another possibility to achieve the same effect is to resort to dual completions: arrangements are made to enable the wells to produce from the two zones at the same time, through separate flow strings.

In some conditions it may be acceptable to complete the wells on both zones at the same time and to produce the two zones together (commingled).

COMBINED PLANS

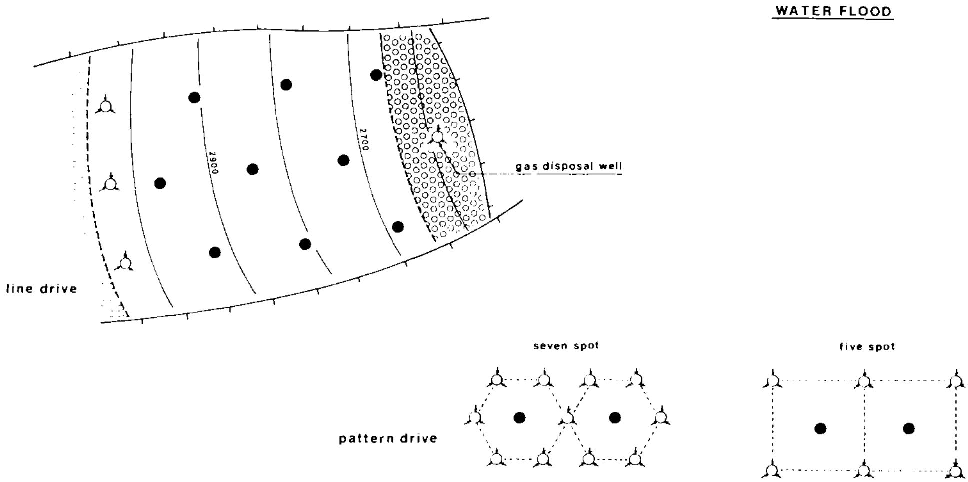


Where two productive intervals occur above each other, it is obviously economically attractive to produce the two zones from the same wells as much as possible. This must be taken into account in making the development plans.

On the other hand, the drainage points for each sand should be in the optimum position for the reservoir conditions in that sand. It is therefore the best approach to design optimal development schemes for each sand separately. The drainage points selected for each sand will not generally coincide, as will become evident when the two plans are superimposed. But it is often possible to make at least part of the drainage points coincide by minor adjustments of their positions.

The sketches above represent a very simple case, where only the difference in the positions of the OWC's and the presence of a gascap in the upper sand require some differences in the plans. In the central portion of the fault block some wells can conveniently be used for both sands, probably by dual completion. The remainder are single completions, either because the lower sand is wet or the upper sand is gas-bearing.

H.4 SUPPLEMENTAL RECOVERY



In normal producing conditions only a (small) proportion of the oil present in a reservoir is recovered; in other words, the recovery efficiency is (much) less than 100%. Various techniques have been – and are being – developed to increase this recovery efficiency.

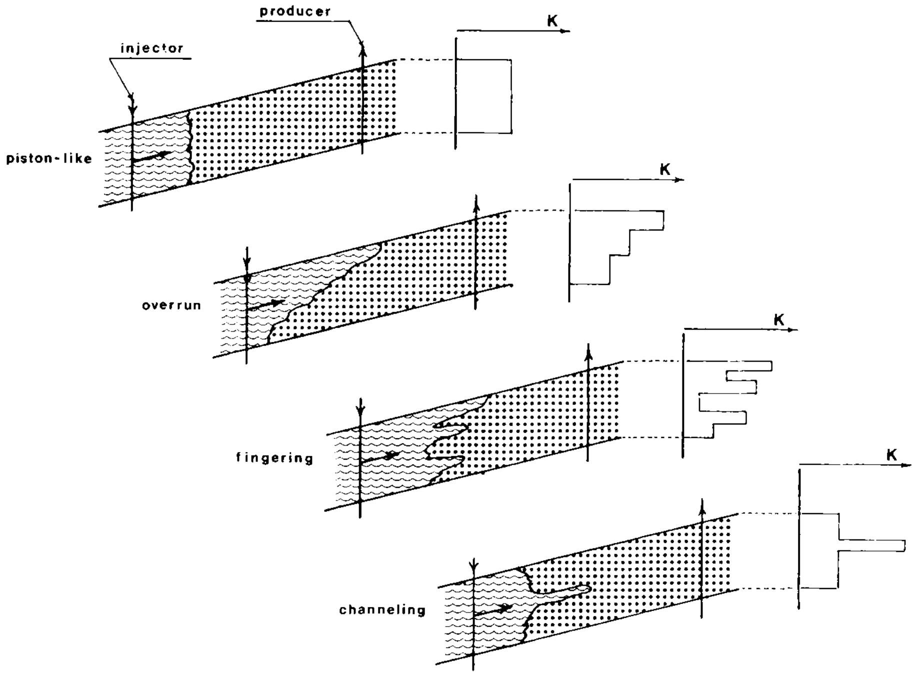
The most common method is pressure maintenance by water injection. This works in two ways: it creates an artificial waterdrive (see Section H.2) and it maintains the pressure in the reservoir. The higher pressure, in the first place, facilitates the lifting of the crude through the wells; secondly, the pressure is kept well above the bubble point which prevents the development of free gas in the reservoir.

Obviously, the numbers and arrangements of producing wells and injectors are determined by the geological conditions and reservoir properties. In a sloping reservoir with edgewater, as sketched above, the most likely pattern is a line of injectors near the OWC, from which the water will travel upwards in the reservoir. In other cases, mainly in flat, extensive reservoirs, pattern drive may be preferable; the seven spot and the five spot are common patterns.

The development plan has to provide for the possibility of water flood. This may be a difficulty in offshore planning: in the design and construction of the platform costly arrangements may have to be included to leave open the option of waterflooding, long before it is known whether or not such flooding will be required.

In the sketched plan a gas disposal well is included; this may be useful to avoid wasting gas produced with the oil and at the same time helps to maintain the pressure in the reservoir.

FLOOD FRONTS



The injected water floods the reservoir around the injection wells, thereby displacing part of the oil contained in the flooded formation: the water pushes or 'sweeps' the oil towards the producing wells.

If the permeability is essentially uniform from top to bottom of the reservoir, the front of the flooded zone will be flat. The displacement is said to be piston-like and the sweep efficiency is high.

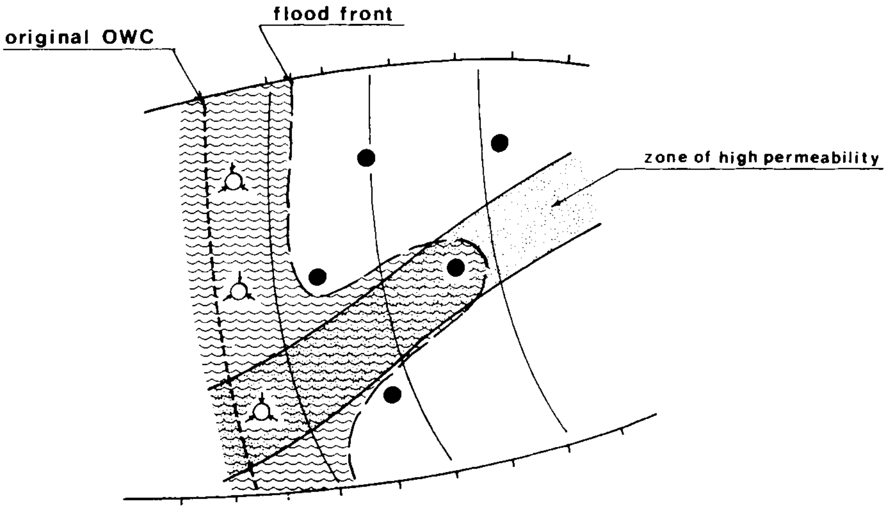
However, many reservoir formations do not have such a uniform permeability profile. For instance, sands deposited in coastal barriers tend to be coarsest near the top (ref. Section D.5) and the permeability profile will go from highest near the top to lowest at the bottom. In such cases the injected water is likely to advance fastest in the zone of high permeability. As a result, the water will reach the producing well(s) first in the top zone ('overrun') and the sweep will be only partial in the lower zones, with consequent loss of overall recovery efficiency.

In formations with irregular permeability profile, the flood front will be irregular and advance in the shape of 'fingers'; here there is a risk of volumes of reservoir being by-passed by the waterflood.

The worst condition is probably where a thin streak of very high permeability exists in an otherwise uniform formation. The water shall then break through into the producing wells rapidly through the high-permeability streak and large volumes of reservoir will be left unswept.

In order to combat these detrimental effects, techniques are being developed to prevent water from preferentially entering the higher permeability zones.

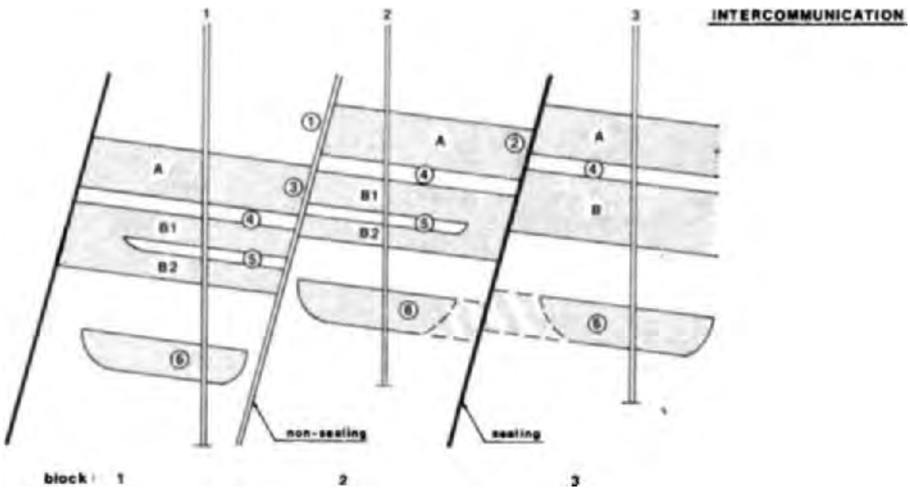
CHANNELING



Apart from permeability variations in a vertical sense, reservoir formations can have pronounced inhomogeneities in a lateral direction; say, a channel type sand embedded in a mass of finer and less permeable barrier sands.

The principle of the line flood is of course that the flood front shall proceed evenly upwards in the reservoir. When the water front reaches a producing well, this well will start producing an increasing percentage of water with the oil. As the total fluid production (water + oil) mostly will not increase appreciably, the oil production will decrease after the breakthrough of the water. Eventually the oil production rate may become so low that the well can no longer be produced economically and has to be shut in.

If a permeability irregularity exists, as in the figure, the water will tend to advance more rapidly up the high-permeability zone and may reach an updip well long before it would have done so if the front were advancing evenly. The well then probably has to be closed in, not only for high water cut, but because maintaining the drainage point active will make the advance of the flood front even more irregular. This in turn could result in by-passing of portions of the reservoir and therefore loss of ultimate recovery.



It will be clear from the foregoing that communication between wells, and the lack of it, is an important element in development planning, both for conventional or primary recovery and for supplemental methods. It is the geologist's task to obtain the best possible picture of the possible channels and barriers between different reservoirs. In the section above some fictional, but not unrealistic, situations are sketched. or primary recovery and for supplemental methods. It is part of the geologist's task to obtain the best possible picture of the possible channels and barriers between different reservoirs. In the section above some fictional, but not unrealistic, situations are sketched.

At point (3) B1 on block 2 communicates with A on block 1. But B2 on 2 will not be connected with A on 1 if the shale (5) is an effective barrier between B1 and B2.

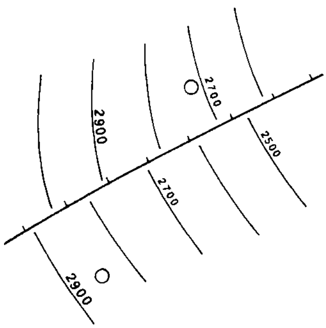
Shale (4) is present in all three wells and may be assumed to be continuous over the area of interest. It is fairly safe to assume that sands A and B are separate reservoirs within fault blocks and could intercommunicate only if juxtaposed across non-sealing faults.

Shale (5), on the contrary, is missing in well 3 and is therefore not fully continuous. So one cannot assume that sands B1 and B2 will effectively be separated in fault blocks 1 and 2.

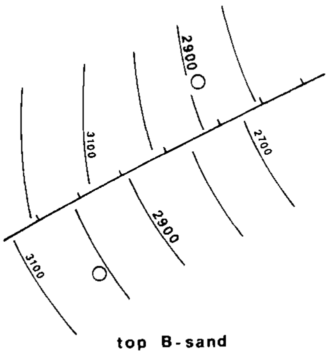
Sand (6) is not strictly in the same stratigraphic position in the three wells and it is likely that it is not continuous over the entire area.

It is up to the geologist to present these conditions to his colleagues in as clear a manner as possible. Particular care should be taken to emphasize the uncertainties in the interpretation, in order to allow the reservoir engineers to select the interpretation which best fits their information.

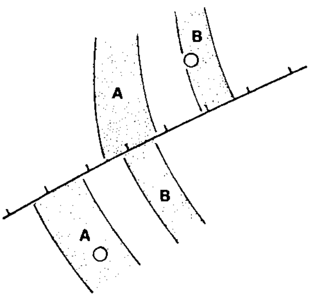
HORIZONTAL SECTION



top A-sand



top B-sand

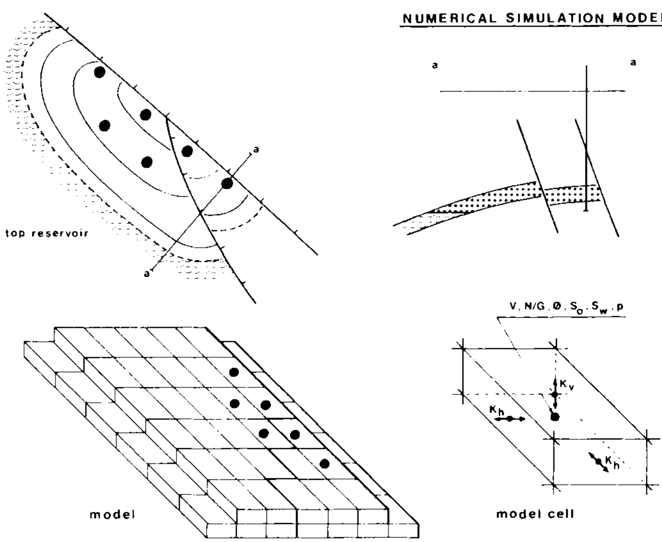


section at 2900 subsea

Juxtaposition of reservoir zones across faults is an important element in reservoir studies, both for conventional and supplemental recovery, and especially in fields where non-sealing faults occur. It is essential for proper planning to know as well as possible which reservoirs could be in pressure communication and have fluid movement between them. If the tectonic structure of a field has been worked out in sufficient detail, it is generally possible to work out which zones are in juxtaposition. But it is often very difficult to devise a convenient method of clearly representing the intricate three-dimensional situation for the use of reservoir engineers and others.

Normally in each field a structure map on the top of each reservoir zone should be available. As can be seen from the example of the two sands A and B, it is not well possible to see from these maps whether or not the two sands are in juxtaposition across the fault. A convenient means of clarifying the situation, without too much work, is to make one or more horizontal sections at suitable depths (comp.Section C.9).

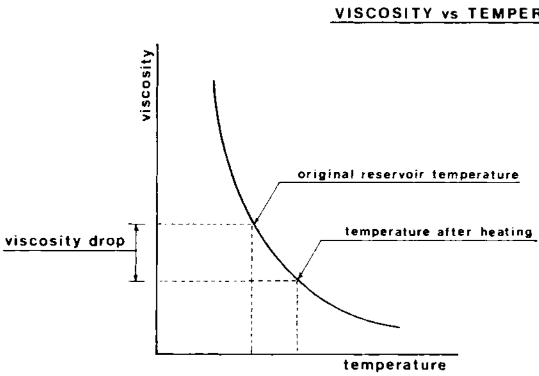
The example shows that there is possible communication between sand A on the northern block and B on the southern block, but B-north and A-south are probably separate reservoirs (unless the fault 'leaks').



Since the advent of suitable computers, reservoir engineering calculations are often carried out by means of numerical simulation models.

The geometry of the reservoir is modelled, with considerable simplification, by a complex of rectangular cells. To each cell are assigned the necessary parameter values to describe cell volume, net/gross ratio, porosity, saturations and pressure. To each interface between two cells permeability values are assigned; because permeability anisotropies often occur, especially between horizontal and vertical permeability, the selected values may be different for each face of a cell. In the case sketched above, the boundary fault would be simulated by impermeable faces; the other, oblique, fault, known to be partially sealing, is represented by faces of reduced permeability. The values of the various parameters assigned to the cells are, of course, derived from what is known of the actual values in the field, so as to make the model as realistic as possible an approximation of reality. The geologist concerned with the reservoir is largely responsible for providing the volumetric data and should ensure that these are used correctly in the model.

Just as space is divided into small cells in the model, so the production history of the field is divided into time steps, perhaps of a few months each. From the cells in which wells are located, the quantity of oil appropriate for the time step is removed numerically and the consequences this has for the other cells, in terms of changes of pressure and saturations, are calculated by the computer. When the complete pressure history of the reservoir has been computed, it is compared with the actual pressure history; if a close 'history match' is found, it may be assumed that the model is realistic. If not, modifications in the input parameters are made, until a good match is achieved. The model can then be used for prediction of the future developments in the reservoir.



In all oil production, by primary as well as supplemental techniques, hydrocarbons are removed from the reservoir and replaced by water. This process, which is never complete (residual oil saturation, ref. Section F.3), is the more effective the lower the viscosity of the oil. Hence the recovery efficiency of light oil, with generally low viscosity, is better than for heavy, viscous oils, in otherwise similar conditions.

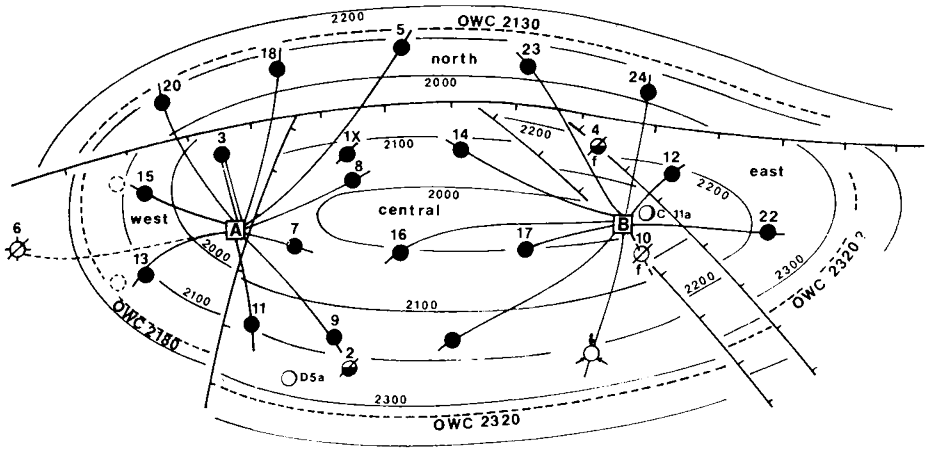
It is not uncommon that for heavy, viscous crudes, the recovery efficiency is no more than 10%, i.e. only 10% of the oil in the reservoir is recovered by conventional techniques. If the viscosity could be reduced, the recovery performance could be improved. To this end steam injection methods have been developed.

The curve showing the relation between viscosity and temperature for crudes generally has a shape like that shown above. If the original reservoir temperature falls on the steep part of the curve, a relatively small increase in reservoir temperature will result in an appreciable reduction of the crude viscosity and, thus, in better productivity. Steam can be injected in a steam-drive process, similar to water injection. Or steam can be blown into a well for some time, after which the well is allowed to produce again from the heated reservoir; this is the so-called huff-and-puff method.

Techniques are being developed in which, instead of reducing the oil viscosity, the viscosity of the injected water is increased, by the addition of chemicals ('polymer drive'). Other methods, again, are based on the use of solvents to, as it were, wash out the residual oil from the pores of the reservoir and carry it to the producing wells; the solvents can be recovered and recycled.

From the point of view of the geologist, these methods present generally the same requirements: in all cases detailed and reliable knowledge of the reservoir geometry, the presence of preferred flow channels and of barriers against flow, and the other variations of the reservoir properties, are an indispensable basis for proper planning and execution of the operations.

H.5 PLAN ADJUSTMENT



During the drilling of the development wells, in accordance with the initial development plan, additional geological information and reservoir data are collected. Often these require adjustments of the development plan, as will be illustrated by the continuing story of our imaginary oilfield.

Platform A was the first to be built. Drilling from this platform started with the two far outsteps for appraisal purposes. Well 5 investigated the north block, found producible oil and defined the OWC on this block. Well 6 was less fortunate: the OWC on the west block proved to be considerably higher than had been expected on the basis of the depth in the central block. Accordingly, the two targets in the west block were moved some distance updip, away from the OWC.

Next, the drilling of the production wells in the central block proceeded: wells 7, 8, 9 and 11. After well 9 was completed, platform B had been constructed and drilling from this platform started as well.

The first well from B-platform, well 10, found the producing interval faulted out; study of the data suggested as the most likely cause the existence of a fault parallel to the fault known from appraisal well 4. Well 10 was abandoned as unproductive and target C11a was added to the drilling programme to provide eventual drainage for the fault sliver between the two parallel faults.

Subsequently, four producers were drilled from platform B, to complete the drainage pattern for the central block. Meanwhile, production and other reservoir data had shown the desirability of water injection for pressure maintenance in the central block. Accordingly, well 21, close to the OWC was drilled and completed as an injector. Moreover, target D5a was put on programme to be drilled eventually from platform A as an injection well.

Meanwhile, two wells, 13 and 15, from platform A completed the drilling in the west block. Two more from the same platform, 18 and 20, provided drainage points for the western part of the north block.

Similarly, from platform B well 22 was drilled to the last target in the east block and wells 23 and 24 completed the drainage for the northern block.

In total, ten wells have been drilled from platform A; well 3 has been tied-back by underwater flowline to the platform; one target, D5a, remains to be drilled from this platform. From platform B ten wells also have been drilled and one target, C11a, remains to be drilled. When all drilling remaining under the present plan has been completed, one slot will remain available on both platforms for later contingencies.

When the two targets presently remaining have been drilled, the field will contain: one exploration well, three vertical appraisal wells and 23 deviated platform wells. Of this total, 19 are producing wells, two are injectors and five were abandoned for various reasons (a not uncommon proportion).

It may be noted that the drainage pattern is rather denser in the southwestern part of the field than in the east; this may be ascribed to better sand development in the western area, allowing denser drainage.

H.6 REVIEW

The planning and execution of development drilling in an oilfield is a task which can be properly carried out only as a team effort of the specialists in the various subdisciplines of petroleum engineering. The production geologist is a member of this team and must in this phase of the field's development cooperate with the other members more intensively than in the earlier phases.

The work of the other specialists, especially of the reservoir engineers, is dependent on the geologist for a large part of its basic information. All the work the production geologist has done, as described in Chapters C, D and F, is intended to provide the best possible description of the reservoir and its contents, for the other specialists to use in their planning work. It is important, therefore, that the production geologist presents this information to the other specialists in the form of drawings and other documents which they can use conveniently.

The work of the production geologist is to a large extent a service to other specialists. This should not be interpreted to mean that he is entitled to turn over his results to his colleagues, without further attention to the use they make of them: he must keep in contact to ensure that the geological aspects of the field are taken into account in the best possible way in the planning. As an example: in the development of a computerized, numerical reservoir model, changes may have to be made in the input of reservoir parameter values for the many cells of the model. It is not impossible that the reservoir engineer would want to alter, say, the porosity figures, in a way which the geologist would feel not to be in accordance with his views of the sedimentological nature of the reservoir. It is then his responsibility to cooperate with the reservoir engineer in order to achieve an alternative, more realistic model.

In Section H.5 some instances were mentioned of changes which had to be made in a development plan because of information obtained during the drilling. This means also that the geologist has to keep continuously in touch with the developments in the field, in order to keep the geological picture up-to-date and to ensure that its peculiarities are taken into account properly in the planning of the further activities.

Chapter I

RESERVE ESTIMATES

I.1 PRINCIPLES

In relation to an oilfield the term 'reserves' obviously refers to the quantity of hydrocarbons which is 'in reserve', i.e. the quantity which remains to be recovered from the field. To know how large this quantity might be is of obvious importance for operational and economic reasons. Therefore, organizations active in the oil industry make serious efforts to obtain the best possible reserve estimates, i.e. estimates which are as realistic, as accurate and, thus, as reliable as possible.

In practice it is not the quantity of remaining reserves which is estimated in the first placc, but the quantity of hydrocarbons that *in total* is likely to be produced from the rcservoir or field. This total quantity produced at the cnd of the field's life, is called the ultimate recovery. For a producing field the following equation applies at all times:

ULTIMATE RECOVERY = CUMULATIVE PRODUCTION TO DATE + RESERVES

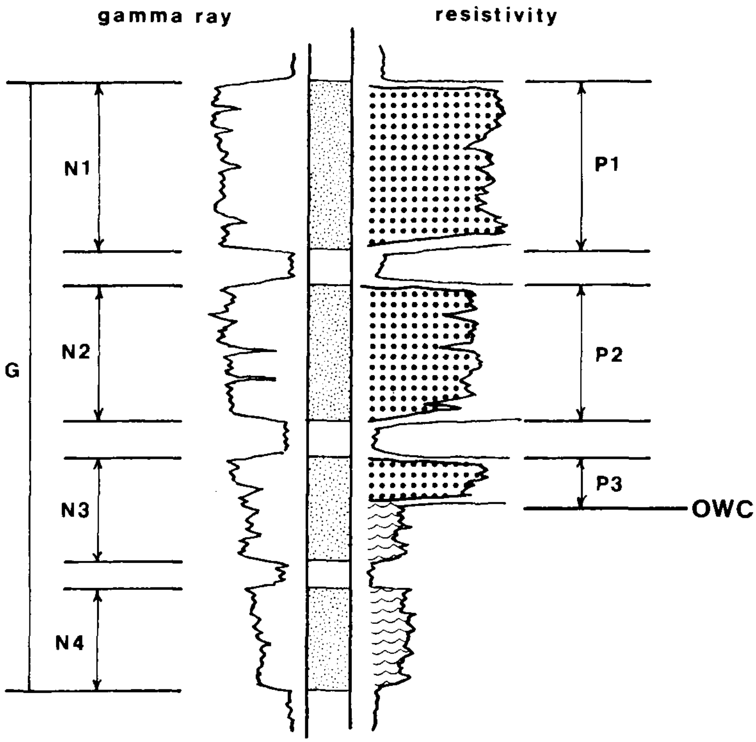
The management requires the most accurate estimates possible. This often leads to a – not unnatural – tendency to use elaborate, detailed, often computerized, methods of estimating. It should be remembered, however, that such elaborate estimating methods are justified only if the data base available for the estimating exercise is also elaborate to the same degree. The use of such sophisticated methods in a young field, where data from few and probably widely scattered wells are available only, tends to suggest a degree of accuracy and reliability which does not really exist. The statement: 'It comes out of the computer, so it must be right', is as wrong here as anywhere.

In such cases all that can justifiably be done is to make a 'back-of-the-envelope' or quick-look estimate. This can often be done in a matter of minutes and experience shows that in many cases such estimates eventually prove to have been remarkably accurate. In this Chapter attention is given mostly to such quick-look methods; more sophisticated techniques require the cooperation of other experts.

There exist several, fundamentally different methods of reserve estimating. Some of these are based on production data, pressure data, etc.; these methods are not of a geological nature and belong in the field of the reservoir engineer. The production geologist is most concerned with the techniques that are implied in the term 'volumetric estimating'; these techniques are the subject of the following discussion.

I.2 SAND THICKNESS

DEFINITIONS



G	= gross interval thickness	= 'gross sand'
$N_1 + N_2 + N_3 + N_4$	= net sand thickness	= net productive thickness
$P_1 + P_2 + P_3$	= net oil-bearing thickness	= net oilsand thickness = (= pay thickness)

An important parameter in volumetric estimating is the thickness of the producing zone. In the figure various types of 'thickness' are illustrated, each of which can, on occasion, play a part in the estimating procedure.

Gross thickness is the thickness of the stratigraphically defined interval in which the (potential) reservoir beds occur, including such non-productive intervals as may be intercalated between the productive intervals.

Net sand – or *net productive – thickness* is the thickness of those intervals in which porosity and permeability are known – or supposed – to be high enough for the interval to be able to produce oil or gas.

Net oil-bearing thickness includes those intervals in which oil is present in such saturation that the interval may be expected to produce oil, if penetrated by a properly completed well.

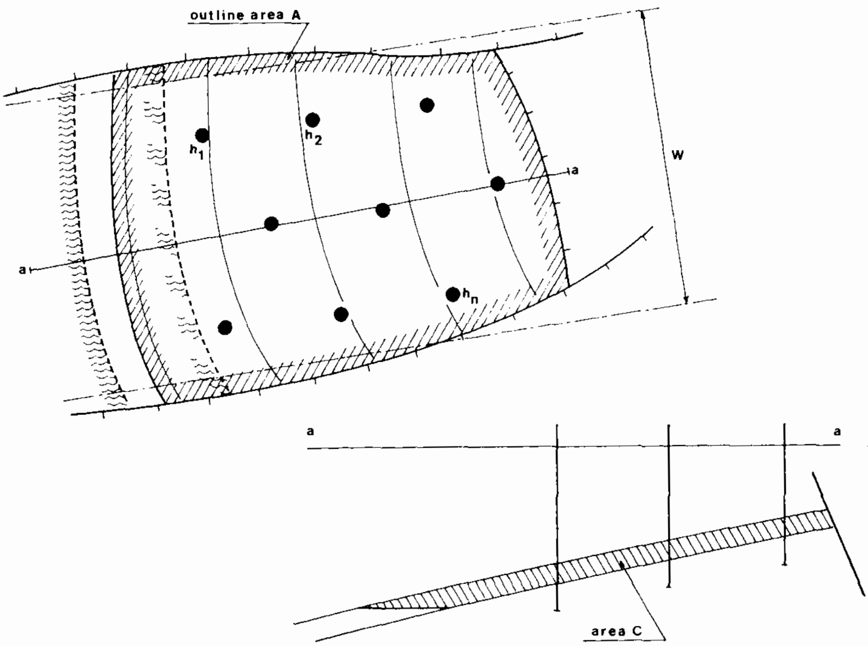
The diagram represents a simple case in which the difference between oil-bearing and non-oil-bearing rock is clearly visible on the logs. This is not always the case: especially in carbonate reservoirs it is often very difficult to establish whether a certain interval will produce clean oil, or oil and water, or water only. To solve this problem belongs to the task of the professional log evaluator and he will be called upon in those cases to provide suitable figures for sand thicknesses.

In this discussion the term 'sand thickness' has been used, because the majority of reservoirs are indeed in sands or sandstones. Strictly speaking, the term should not be applied to carbonate rocks, but in practice it is often used colloquially also for reservoir rocks in which no real sand is involved.

This ambiguity could be avoided by using the term 'pay', which is neutral as regards the lithology of the reservoir rock. Originally the term, which is derived from ore mining, obviously referred to intervals which will 'pay', in other words: which will produce oil or gas in commercial quantities; it is defined as such in the 'Glossary of Geology' of the American Geological Institute (fourth printing, 1977). However, a tendency appears to be developing in the industry to include under the heading 'pay thickness' all rocks which are suitable reservoir rocks, oil-bearing or not; in other words, the term would be equivalent to the net sand thickness, not all of which necessarily 'pays'. It may be better to avoid the term 'pay' altogether and to use a less convenient, but unambiguous circumlocution, such as those defined above.

I.3 ROCK VOLUME (GROSS)

QUICK-LOOK



Another important element in volumetric estimates is the volume of the oil-bearing rock in the reservoir under consideration. Various techniques for carrying out this part of the estimate are available, ranging from the very simple to sophisticated computer programme packages. The simple methods have the advantage of being quick, and not necessarily much less reliable than the more sophisticated approaches. Two very simple methods are sketched in the figure above.

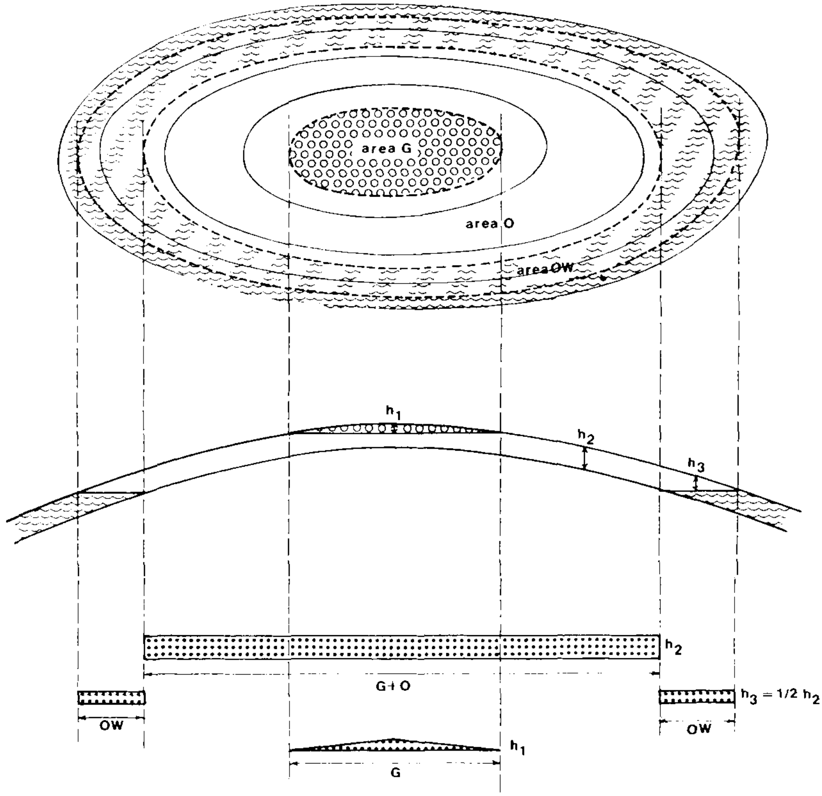
In the first method the oil-bearing area A is measured; in the case shown, after correction for the wedge-shape strip overlying the OWC. This area is multiplied by the average gross thickness of the reservoir horizon, as measured in the wells:

$$V_{gr} = A \times \frac{h_1 + h_2 + \ldots + h_n}{n}$$

Another simple approach is to measure the cross-sectional area C of the reservoir and to multiply this by the average width of the fault block W. This method is applicable only in reservoirs of more or less rectangular shape and, preferably, of nearly uniform thickness:

$$V_{gr} = C \times W$$

GEOMETRICAL SHAPES



In somewhat more complicated cases, it may be useful to transform the reservoir – mentally – into elements of simple geometrical shape, the volumes of which can be readily calculated from the respective areas.

The main element of the reservoir, sketched above, is the volume where the full thickness of the reservoir is filled with hydrocarbons. The area corresponding to this volume is that underlying the gascap, plus the oilring down to the inner limit of the OWC (= its intersection with base reservoir). This volume can be simplified to a disk with base-area equal to $G + O$ and height h_1 (i.e. the full gross thickness of the reservoir).

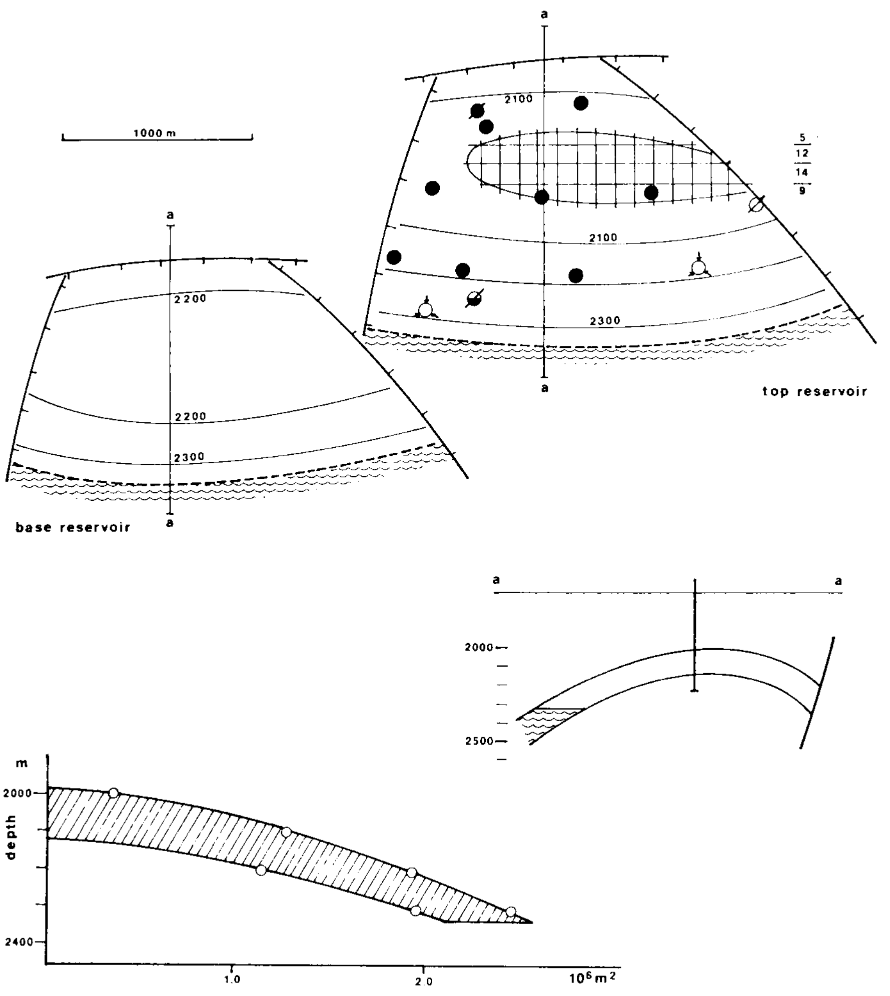
The volume of reservoir overlying the OWC is a wedge-shaped ring, which can be closely approximated as a ring of rectangular cross section, with a thickness of half the total thickness of the reservoir zone.

Finally, in order to obtain the oilbearing volume, the gascap has to be subtracted. The volume of the gascap can be represented as a cone with height equal to the distance between GOC and the highest point of the reservoir (= gas column height).

The total oil-bearing volume then becomes:

$$V_{gr} = (G + O) \times h_2 + OW \times \tfrac{1}{2} h_2 - \tfrac{1}{3} G \times h_1$$

AREA vs DEPTH GRAPH



A convenient method for application in most cases uses the 'area vs. depth graph'; it is a suitable method for all cases where the geometry of the reservoir is represented by contour maps, either structural or some form of thickness map.

The case illustrated above is a fault block reservoir of simple structure and fairly uniform thickness. Structural contour maps on top and base reservoirs are available. The area enclosed by each contour (and stretches of fault trace) is measured. These measured areas are plotted against the corresponding depth; this results in separate curves for Top and Base Reservoir. The area enclosed by these two curves represents the reservoir volume.

It will be clear that the area measured for any contour includes also the areas enclosed by all lower-numbered contours. For instance, the area of the 2100 m contour includes also the area of the 2000 m contour, etc.

In this, and other, methods, measuring of areas is an important element. Short of using the computer, which requires some form of digitization of the maps, a planimeter is the appropriate instrument for this purpose. In many case it is sufficient to use the quick-look method of counting squares. In the example on the previous page, a grid of squares has been drawn over the area of the 2000 m contour; it is a very minor effort to count the squares inside the contour and to convert the resulting number into square metres (40 squares equivalent to 10^4 m^2 each).

Close attention must be given to the units of measurement used for the graph. Particularly in the last step where the area between the curves of the area vs. depth graph, measured in areal units, has to be converted into volume units of the reservoir. Experience shows that it is very easy to put a decimal point in the wrong place. Moreover, in many oil-producing areas, depths in a well are measured in feet and surface distances in metric units or miles!

The method is, of course, not confined to use in simple reservoirs, as shown in the sketch. In case the entire oil-bearing volume is underlain by bottom water, the curve for base reservoir is replaced by a horizontal line at the OWC depth.

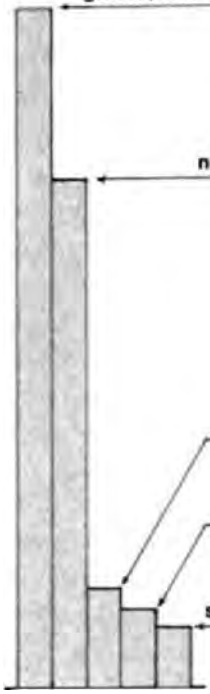
Also, the method can be used on thickness maps. If a reservoir is flat, but the net sand thickness varies appreciably over the reservoir area, it is convenient to construct an isochore map, applying such sedimentological knowledge of the reservoir as may have been collected. The 'Area vs. Depth Graph' is then replaced by an 'area vs. thickness graph', constructed on the same principle.

The methods for estimating rock volumes discussed in the foregoing are all manual techniques; such methods are convenient in fields with not too many wells and not too simple tectonic structure. In larger fields it may be more economical to use one of the many computer packages available, either commercially or within the own organization. Such programmes probably use some form of area vs. depth method.

The input for these programmes may consist of the 'raw' data: well coordinates and corresponding depth or thickness figures; the computer will process these by some form of mapping technique, e.g. triangulation (comp. p. 75). In other cases it may be advisable to 'pre-digest' the well data by constructing structural or thickness maps, especially in cases of complex geology, where the geologist may produce better results than the machine. For use as input, the maps of course have to be digitized.

Whatever method is applied, it is obviously up to the user-geologist to provide the most suitable input, applying his knowledge of the geology of the reservoir.

I.4 VOLUMETRIC EQUATION



VOLUMES	FACTORS	SYMBOLS	EXAMPLE factor values	EXAMPLE volume units
gross (oilbearing) rock volume		V_{gr}		100
	net/gross ratio	N/G	75%	
net oilsand volume		V_n		75
	porosity	Ø	20%	
pore volume				15
	oil saturation	$1 - S_w$	75%	
oil-in-place				11,25
	"shrinkage"	1/B	0.8	
stock-tank oil initially in-place		STOIIP		9

$$\boxed{V_{gr} \times \frac{N}{G} \times Ø \times (1 - S_w) \times \frac{1}{B_o} = \text{STOIIP}}$$

From the gross oil-bearing rock volume, determined by one of the methods discussed in the preceding Section, the volume of hydrocarbon reserves now has to be calculated. This is not strictly a geological operation, because input from other disciplines is required. Nevertheless, the production geologist provides a considerable part of the basic information and he should be capable of forming an opinion on the reliability of the entire exercise. This he can only do if he is thoroughly familiar with the procedure.

The commonly used fundamental equation is shown above. In the tabulation the various parameters involved are listed, together with the symbols conventionally used. Also listed are assumed values for each of the factors, i.e. such values as are often found in practice, which will give some idea of the magnitudes that can occur. The final column shows how an original gross volume of 100 arbitrary units is reduced at each subsequent step in the calculations.

The *gross oil-bearing rock volume,* per definition, includes rocks that are not sufficiently porous and permeable to produce hydrocarbons, cf. p. 202. These non-reservoir rocks do not contribute to the reserves and therefore have to be excluded from the calculation.

This is achieved by multiplying the gross volume by a figure for the *net-to-gross ratio.* The correct value for this factor is derived from logs and should be contributed by the log evaluator. The value of this parameter can, of course, vary over a wide range. However it is unlikely that in a productive reservoir the non-reservoir rock will exceed the productive rock. In the example of the tabulation on the previous page a value of 0.75 or 75% was arbitrarily assumed. The gross volume of 100 units is reduced to 75 units of *net sand volume.*

The next step is to remove the rock material from the calculation: the *porosity* fraction is introduced. Porosity values can also vary over a large range, but in practice values higher than 30% or lower than 10% are not too common. In the example a value of 20% was assumed, resulting in a *pore volume* of 15 units.

In the pores of the reservoir rock an irreducible water saturation is always present, cf. p. 150. Values for this S_w are derived from log interpretation and can vary over a wide range. Roughly speaking, it is unlikely that a rock with more than 50% water saturation will produce oil. On the other hand, an S_w value of less than 10% is unlikely in nature. Because S_w can be measured from logs, the *oil saturation,* S_o, is introduced in the equation as $(1 - S_w)$. If no more accurate data are available, as may well be the case in a young field, it is generally a not unreasonable approximation to assume a value for S_o of 75%. In the example this reduces the pore volume of 15 units to a volume of *oil-in-place* of 11¼ units.

If a unit volume of reservoir fluid could be brought to the surface intact and there left to expand, it would lose part of the lightest components to the atmosphere by evaporation and thus lose part of its volume. This reduction of oil volume from the reservoir to surface conditions is called the *'shrinkage'.* Conversely, a barrel of produced oil, as it is measured in the stock-tank, is equivalent to a larger volume in the reservoir. In reservoir engineering calculations a factor is used, called the formation volume factor, B_o: the volume of oil produced is multiplied by this factor to obtain the corresponding volume of reservoir fluid extracted. In the equation the shrinkage appears as $1/B_o$. The actual value of the shrinkage depends of course on the composition of the reservoir fluid: lighter crudes being likely to lose more volume than heavier crudes. The value assumed in the example, 0.8, is not an unlikely average in practical conditions.

This brings the calculation to the end of the first stage: it results in a figure for the volume of oil that would be received in the stock-tank if all the oil which was present in the reservoir in its virgin state could be produced. This is the volume of *stock-tank-oil-initially-in-place,* or STOIIP. The example shows that, assuming values for the factors which are common in practice, out of 100 units of gross oil-bearing rock volume, only 9 units are oil.

This STOIIP volume is a favoured quantity for use in studies intended to determine the potential economic value of an oil accumulation. This is mainly because STOIIP is determined from properties of the reservoir and reservoir fluids, which are, in principle, measurable. For the next step, the conversion of STOIIP to actual producible reserves, the influence of production techniques has to be introduced. In this phase consideration is given to the question: starting from a given volume of STOIIP, what production techniques should be applied to achieve the most economical results. In practice it is useful, therefore, to agree on a figure for STOIIP, before introducing the further, technological complications.

This also implies that the production geologist is essentially concerned only with the first phase of the calculations: the determination of STOIIP. The introduction of the technological factors is up to the reservoir and production engineers.

STOIIP is the quantity of oil originally present in the reservoir, not all of which can be produced. How much can be produced, depends on the production techniques applied and on the reaction of the reservoir to these techniques. The fraction, or percentage, of STOIIP that can eventually be produced is called the *recovery factor* and the following equation applies:

$$\text{STOIIP} \times \text{RECOVERY FACTOR} = \text{ULTIMATE RECOVERY}$$

The recovery factor can vary over a very large range. A factor of 0.10 or 10% is probably the minimum that is economically acceptable in most cases. In very favourable conditions, for instance a strong natural waterdrive in a homogeneous reservoir, values up to 75% may be reached. The economic importance of the recovery efficiency which can be attained is obvious and, also, that every effort shall be made to increase the recovery factor as much as is economically possible. Nowadays often by the application of supplemental recovery techniques as discussed in Section H.4.

I.5 PROCEDURES

The actual procedure for calculating STOIIP depends on the natural and technical conditions in the field under study.

In a small or immature field, where only a few wells have been drilled, the available information is probably insufficient to justify using elaborate approaches and it is likely to be best to apply average values for the various factors. In cases of very incomplete information, for instance where only an exploration well has been drilled yet, and a reserves indication is wanted nevertheless, it may be necessary to resort to values, which in themselves are only estimates. Likely figures for porosity, S_w and B_o can be chosen if the lithology of the reservoir rock is known; the selection of more or less realistic values is largely a matter of experience for the production geologist and the log evaluation expert.

On the other hand, there are the very large fields with, say, several tens of wells. Each well then probably has a comprehensive set of logs and one or two complete sets of cores through the reservoir horizon have probably been taken in the field. In these cases more elaborate techniques are required in order to arrive at reserves figures which have the best chance of being a suitable approximation of reality.

If in such a case, as is likely, the sedimentological development of the reservoir rock varies noticeably over the field area, the application of the $V_{gr} \times N/G$ method is no longer justified. In those cases the geologist probably already has made a net sand map, representing the distribution of the productive thickness over the field area. This map can then be used to arrive directly at the most realistic value for V_n, the net oilsand volume. In Chapter D it was discussed how, with he help of sedimentological knowledge, a rational approach to the mapping of reservoir rock distribution can be attempted; this will lead to, more or less, realistic maps for reserve estimating purposes.

The problems are more onerous in the case of porosity. The simplest approach is to average the porosity values measured in each well, for which a computer programme is probably available, to map these averages and to construct an iso-porosity map.

Experience shows, however, that this approach may result in unrealistic volumetrics. Porosity is a property which varies with space much more markedly than, for instance, net sand thickness. Already in the depositional stage local effects can produce small volumes of rock in which the porosity differs considerably from that of the remaining bulk of the rock; for instance, in current-deposited sands a small spatial or temporal change of the current velocity can result in the deposition of finer material with lower porosity. Similarly, diagenetic effects can be extremely local; for instance, in some cases faults are accompanied by zones of sharply reduced porosity. If a well happens to penetrate such a small body of low-porosity rock, its average porosity value may well be much below the level of most of the remaining reservoir.

The problem obviously is that the porosity values measured in a single well are not necessarily representative for more than a small volume immediately surrounding the well. A simple mapping procedure by interpolation of well values will then tend to apply this exceptional, local value to much too large a volume of reservoir, with consequent inaccuracies in the volumetric estimate.

This is particularly detrimental because porosity is, numerically, an important parameter in the calculations: if the porosity for a certain volume of rock is incorrectly reduced from, say, 20% to 15%, the reserves figure for the volume is reduced by one quarter. The only remedy would appear to be a close study of the reservoir geology in order to arrive at an understanding of the nature of the porosity variations, which in turn will help to make the iso-porosity map a more realistic product.

Water saturation is dependent partly on the lithological characteristics of the reservoir rock. Porosity also depends on lithology and there exists a – usually not well quantifiable – relation between the two properties. A map of S_w variations can be produced in the same way as the iso-porosity map; for the actual STOIIP estimate this map would of course have to be converted to a $(1 - S_w)$ map.

The remaining parameter, the formation volume factor or B_o, should be well-known from reservoir engineering observations at the mature stage of a large field and should present no problems to the geologist.

The estimation of STOIIP thus becomes a matter of handling three maps – net thickness, porosity, oil saturation – instead of three figures. The most obvious procedure is to multiply the three maps. This can be done by hand: two maps are superimposed, the contour values at each intersection point of two contours are multiplied and a new map is constructed; this in turn is then multiplied with the third map. But this is a laborious exercise, which can be avoided in two ways.

One method is not to map the three parameters separately but to multiply the three average values for each well to arrive at what is called the equivalent oil column:

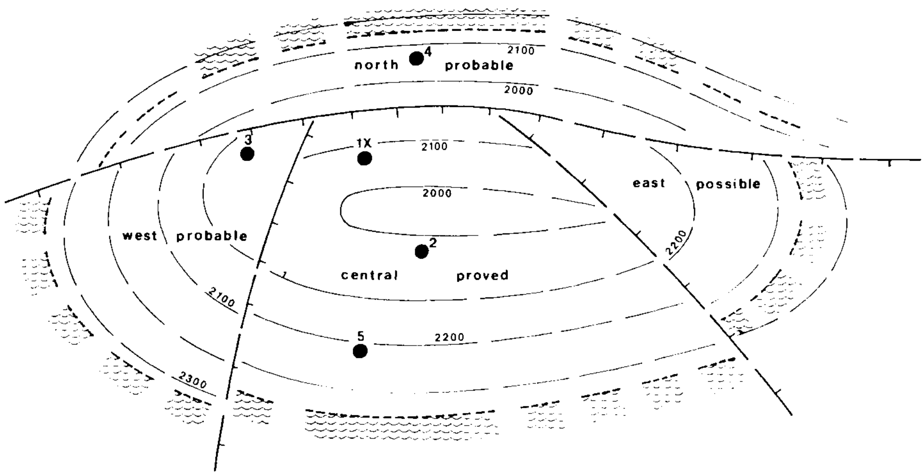
$$V_n \times \phi \times (1 - S_w) = \mathrm{EOC}$$

A map of EOC value per well is then constructed and handled volumetrically by one of the methods described. It may be objected that immediate insight into the geological causes of the EOC variation over the reservoir area is not possible and that therefore only an automatic numerical contouring approach is possible. This may be only partially true: the three component parameters are all related to lithology and thus some geological understanding may be available to help in the mapping operation.

The other simplification method is, naturally, to digitize the three maps and to multiply using one of the available computer packages.

In between these extremes of procedure – multiplication of average figures and multiplication of carefully produced maps – other possible approaches can be applied, depending on the quality and completeness of the information available. For instance, in a particular case it may be best to: derive V_{gr} from structure maps; apply an average value for N/G, if this parameter is sufficiently uniform over the area; map porosity; apply an average for S_w. The optimum procedure in any particular case should be selected by the production geologist in cooperation with the petrophysicist and the reservoir engineer.

PROVED - PROBABLE - POSSIBLE



The procedures discussed in the preceding sections result in a single figure for the STOIIP (or ultimate recovery or reserves) of the reservoir. From this single figure the user of the information cannot form an opinion on its reliability. But not all estimates are of equal reliability. If an estimate is made for a reservoir that is fully drilled-up and has already produced a part of its oil, the information required for the estimate is probably fairly complete and the resulting estimate correspondingly accurate (= realistic). But in a young reservoir, in which only two or three wells have been drilled, only a rough 'guesstimate' of the volumes of oil present can be made.

The desire to give the user some indication of the reliability of a specific estimate has long been felt. Traditionally the requirement has been met by applying the 'Proved – Probable – Possible' classification system.

The generally accepted definition of proved (or proven) reserves is: 'the quantity which analysis of geological and engineering data demonstrates, with reasonable certainty, to be recoverable in the future from known reservoirs under the prevailing economic and operational conditions'. The important phrase is 'with reasonable certainty', which may be translated as 'nearly 100% probability'. In the example sketched above, the central block has been proved oilproductive by three wells and the structure and the position of the OWC have been established with fair reliability. The amount of oil that would be estimated for this block would come in the Proved category.

The definitions of Probable and Possible reserves are much less well established. It may be best to adopt, for practical purposes, the meaning which the two words would have in common everyday usage. Probable reserves will 'probably' be recovered, but this is not, of course, certain. Possible reserves will have no more than a (small) chance of being present and recoverable.

In the example the west and north blocks have been brought into the Probable category. In both blocks one well has been drilled and has proved the presence of producible oil. However, in the west block the depth of the OWC has not yet been established; for a reserve estimate the same depth as in the central block would be assumed but this is by no means certain. If the OWC is higher than assumed, the reserve estimate would be too high. In the north block the structure on both sides, away from the one central well, is still known only poorly and this leaves a considerable margin of uncertainty.

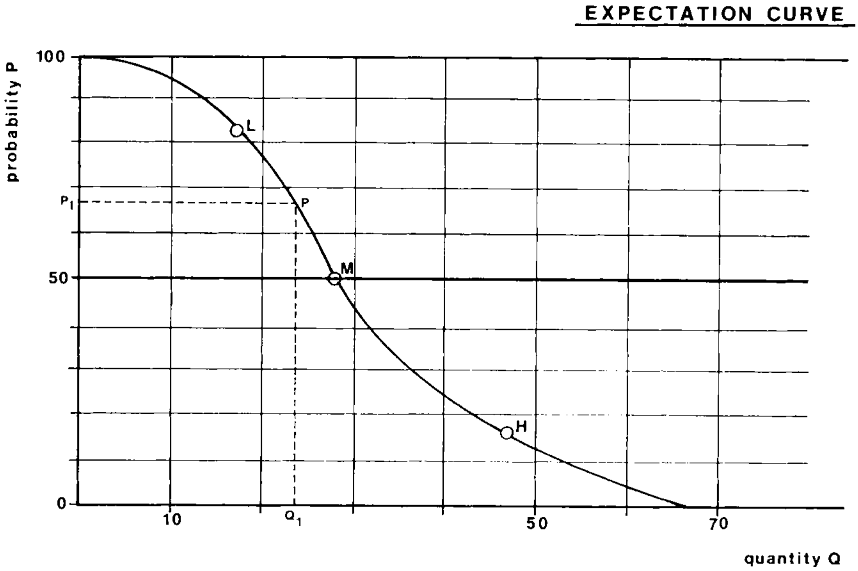
The Possible category is represented by the east block, which no well has yet penetrated. This case demonstrates the fundamental difficulty in attempting to define the uncertainties involved in reserves estimating; in fact, two types of uncertainty have to be considered. First, there is the question whether or not any producible oil is present in the block at all. In this case the chance that the answer to the question is positive seems fairly good: oil has already been proved on the three other blocks on the structure. Secondly, there is the possibility of inaccuracies in the volumetric estimates, because of insufficiency of the data base. This uncertainty, of course, also exists in the Probable category and, to a lesser extent, in the Proven category.

This problem also affects the attempts to quantify the uncertainties inherent in reserves estimates.

For the Proved reserves this is not too difficult: per definition the probability of the estimated quantity indeed being recoverable is 1.0 or 100%. (Although the phrase 'with *reasonable* certainty' in the definition may rather suggest a somewhat lower figure, say, 90%). If the reserve estimate is to be used for operational or commercial purposes, the estimated quantity can therefore be included for the full 100%.

There is – or has been – a tendency to assign to the Probable category a probability of 50%, which appears suitable at first sight. However, it has led to the practice of including the probable reserves in a figure for total reserves at 50% or one half of the estimated value. The west block of the example illustrates the dangers of this system. The estimate for this block would be based on the *most likely* position of the OWC (i.e. the same as on the central block). The OWC could be higher, in which case the reserves estimate would be too high; on the other hand, the OWC could also be lower and then the estimate would be too low. In other words, the estimate as made is also a *most likely* figure and it is not correct to include in total reserves only half of this most likely quantity.

Similarly, the probability for Possible reserves would be taken at 25%, implying that only one quarter of the most likely value would be included in total reserves.

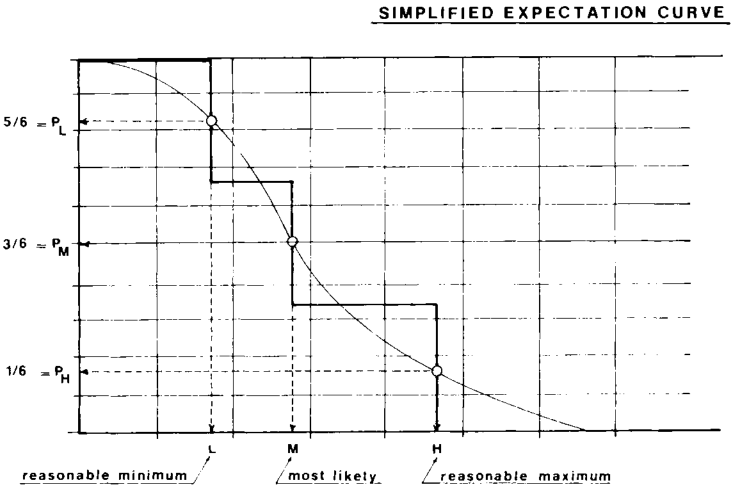


In order to overcome the disadvantages of the Proved-Probable-Possible system, the technique of the expectation curve may be applied. The main advantage is that instead of single-figure estimates, ranges of possible values are established, which leads to much improved evaluation of the geological and technical uncertainties.

In the complete form of the system, the various parameters of the fundamental volumetric equation (ref.Section I.4) are introduced as statistical probability distributions, which may take various shapes. The multiplication of the distributions is carried out by statistical (computerized) methods, such as the Monte-Carlo technique.

The result is an expectation curve, such as is shown above. The curve represents all the possible values which the quantity Q can have, together with the probability that quantity Q has at least that value. For instance, the point P shows that there is a probability P_1 (about 0.67 or 67%) that the quantity Q has a value of at least Q_1 (about 23 units). The high end point of the curve indicates that there is 100% probability (that is: absolute certainty) that Q is larger than zero; in the case of oil reserves this obviously means that the presence of oil has been proved. The other end point shows that it is considered impossible that Q should be larger than 66 units.

Thus the expectation curve gives a comprehensive view of the quantities of reserves that are thought to be possibly present, but it is perhaps not very convenient for administrative and communication purposes: one cannot well present a manager with a complete expectation curve every time he asks for a reserves figure. Some simplification is desirable.



A convenient way of simplifying the expectation curve is to divide the curve into three equal steps, thus defining three interesting points, which together give a good impression of the range of possible values of the quantity Q. The three points are called the low, medium and high values, or L, M and H.

The most useful point is the M value, which is the value with 50% (3/6) probability, meaning that this value has equal chances of being too high and too low. In other words it is the 'most likely' value. If it is desired to express the reserve estimate in one figure, this value is convenient to use.

Two other convenient points are the values with 5/6 (83.3%) and 1/6 (16.7%) probability, which are referred to as the 'reasonable minimum' and 'reasonable maximum' values. The quantity of oil corresponding to the reasonable minimum value is almost certain to be present and recoverable. It therefore closely resembles the Proved reserves of the old system.

Similarly, the reasonable maximum is not the absolute maximum (which has a probability of zero and is of little interest), but the highest value that one would in practice believe might be present, with a lot of luck.

The simplified expectation curve provides the geologist with a convenient quick-look procedure for probabilistic reserve estimating. Starting again from the fundamental volumetric equation, the way to proceed is to estimate for each of the parameters not one single 'most likely' value, but also to make a guess at the 'reasonable' minimum and maximum values. This is, of course, a subjective approach, but with some experience it is not too difficult to obtain acceptable results. The multiplication of the parameters has to be carried out probabilistically, for which a simplified method can be provided.

		L_1 4	M_1 7	H_1 10
L_2	3	12	21	30
M_2	5	20	35	50
H_2	8	32	56	80

$$L = \frac{12 + 20 + 21}{3} = 17.7$$

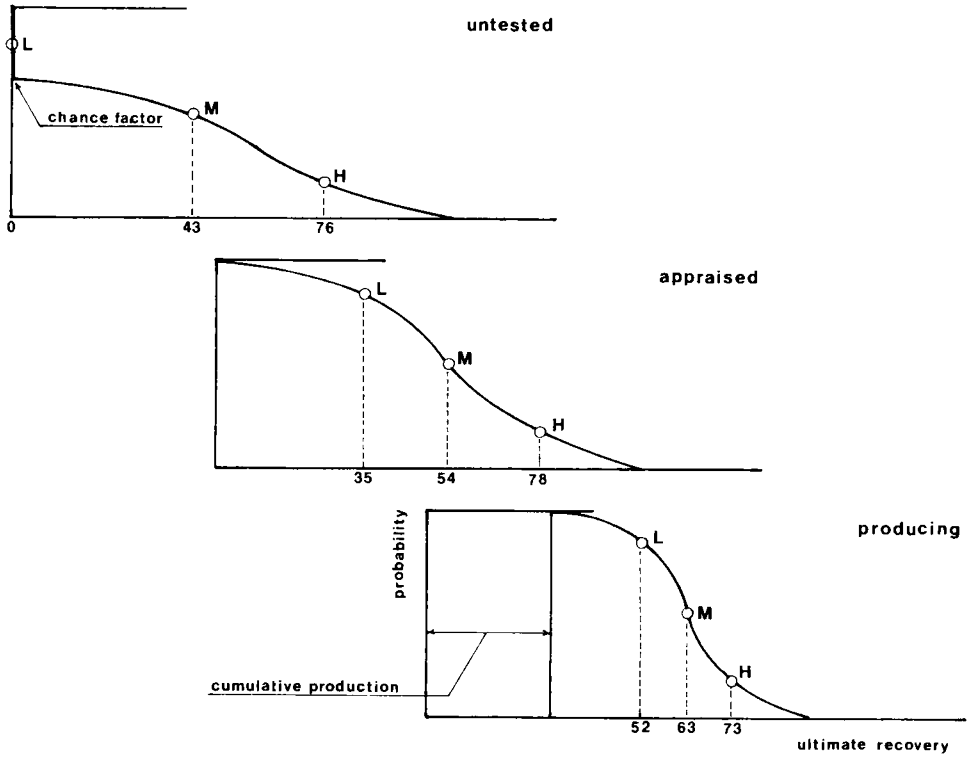
$$M = \frac{30 + 32 + 35}{3} = 32.3$$

$$H = \frac{50 + 56 + 80}{3} = 62.0$$

A simple way for multiplication of two sets of *L-M-H* values is to set up a matrix of nine squares, with the two sets of figures each arranged along one side. In each square the product of the corresponding line and column figures is entered. The resulting nine values are divided into three groups: the three lowest, three medium and three highest products. The averages of each set of three values give the required *L-M-H* values. If these values have to be multiplied again by another set of three, the operation is of course repeated.

A similar operation is applied when the reserves of a number of reservoirs have to be added together to produce the total for a field (or a number of fields for an area). There will be a tendency to add up all the *L* values, all the *M* values, etc. This would lead to an unnecessarily pessimistic minimum value for the total and to an unwarranted optimistic figure for the maximum. Instead, the addition is carried out stepwise with the matrix technique, whereby, instead of products, the sums of line and column are entered in the squares.

CHANGING EXPECTATIONS



As development of a field proceeds, the uncertainty about the quantities of petroleum to be expected changes, as a result of more information coming in; this finds its expression in the shape of the corresponding expectation curves.

The first curve sketched above represents the situation before the discovery well has been drilled. Based on the scanty information available (seismic, regional knowledge) an estimate of the reserves in the prospect can be made and expressed as an expectation curve.

It is not certain that there is any oil at all present; this can be expressed as a chance factor, with which the entire expectation curve is multiplied. The curve then does not start at 100% probability, but at the level of the chance factor, about 70% in the example. This means that the 'reasonable minimum' value, at 83.3%, equals zero, which is correct for this represents the case that there is no oil in the structure. Deciding on a likely chance factor is a tricky operation and exploration organizations have spent much effort in improving the objectivity of the choice. The production geologist is not generally confronted with this difficulty, because in the fields he deals with the presence of oil is assured!

Once the discovery well has been drilled and a few appraisal wells have provided additional information, the decision whether or not to develop the field has to be taken. This is naturally a time for a careful evaluation of the prospects. The second curve, shown on the preceding page, represents the estimate as a conventional expectation curve.

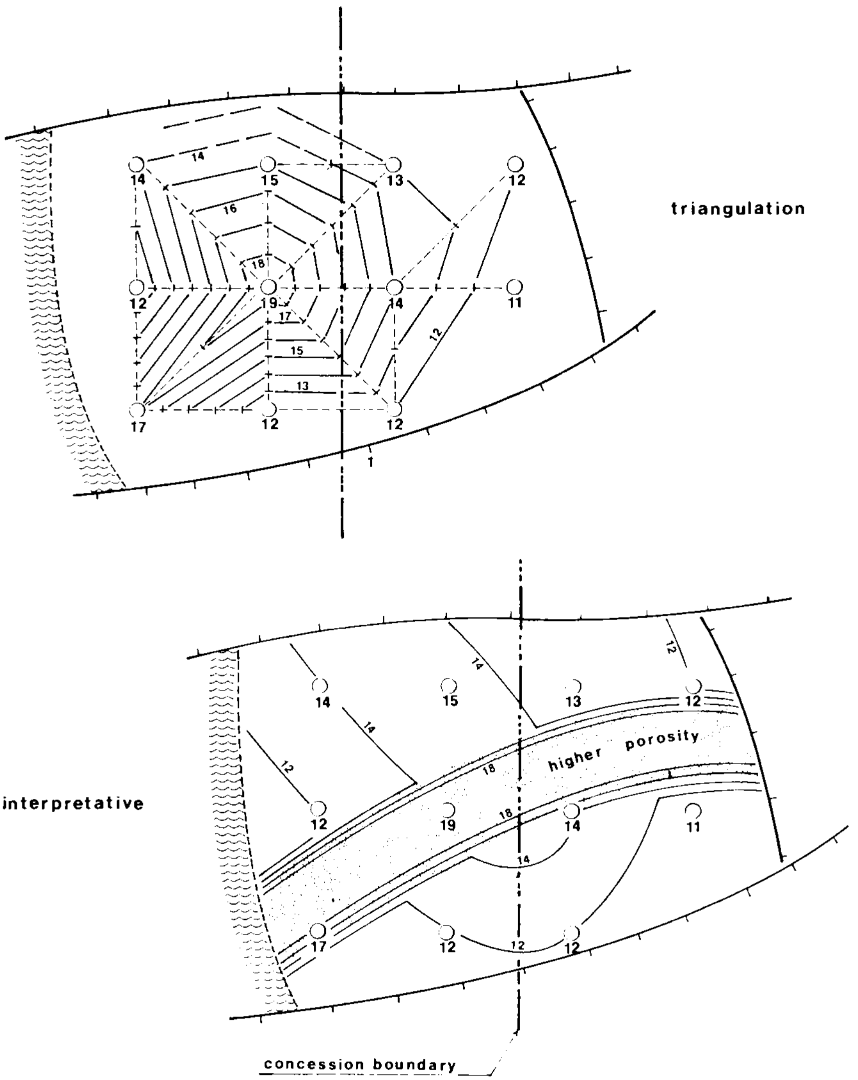
After a part of the STOIIP of the field has been produced, the expectation curve changes again. First, the oil already produced has achieved the status of 100% probability: there can be no doubt as to its existence! The expectation curve representing the amount of oil still to be produced, starts at the value for Q equal to the cumulative production to date.

Secondly, the shape of the expectation curve has changed. Because at this stage of the field development the information available has increased considerably, compared to the stage after initial appraisal, the *range* of the possible reserves values has become much smaller. Graphically this can be seen by comparing the steepness of the lower two curves on the previous page. Numerically it means that the L, M and H values are closer together in the later stages. In fact, when the field has reached its ultimate recovery and is abandoned, the expectation curve would be a vertical line (if anyone would take the trouble of constructing one at that stage).

In the example the M or most likely value increases between the second and third curves. This implies that during the development of the field the quantity of oil in the reservoir has been found to be greater than was thought originally. This is not an uncommon situation: field extensions are often found during development. But it is not necessarily true of all cases: fields which prove disappointing as development proceeds are certainly not rare!

I.7 UNITIZATION

POROSITY MAP FOR EQUITY



Many oilfields are not the property of one single owner, but are owned by two or more owners. In earlier days each owner would develop his own part of the field, which often resulted in overdrilling and waste of investment. At present it is more usual for owners to come together and to agree on some form of joint operation or unitization of the field. Generally, one of the owning parties will be appointed operator and will develop and exploit the entire field as if it were his own, under the supervision of an operating committee of owners' delegates. Very complex operational and legal arrangements are worked out to protect each party's interests.

As a general principle, the operating costs of the unit and the proceeds of the oil produced are split-up amongst the owners in proportion to the amount of 'reserves' underlying the acreage each owns. The portion which each owner has to contribute to the expenses and will receive out of the proceeds, is referred to as the 'equity', generally expressed as a percentage. The importance of the arrangements to arrive at a fair determination of each party's equity is evident: in a sizeable field a difference of one percentage point in the equity can mean a difference of many thousands of dollars, maybe even as high as a million.

In practice, equity determination is a highly labour-intensive and time-consuming process, involving much negotiation between members of management and staff of the companies which joined the unit. One cause of the difficulties is that the 'reserves' on which the equities are to be based can be defined in different ways. The most common possible bases being either 'oil-in-place' (or rather STOIIP) or 'ultimate recovery'. The latter possibility is the more complex, because besides the uncertainties of the volumetric STOIIP determination the recovery factor is involved. This factor, dependent as it is on the efficiency of the recovery techniques applied, comprises an even larger margin of uncertainty.

But even the determination of oil-in-place generally leads to considerable disagreement: each party in the discussions naturally tends to work towards the highest equity obtainable and will try to get those methods adopted which it considers most favourable to its own interest. In order to offset this tendency it will be tried to use methods which can be viewed as 'objective' and therefore equitable; the problems this implies and the possibilities of inequitable results may be illustrated in the example sketched on the previous page.

The field is divided between two owners along the north – south 'lease-line' or concession boundary (It may even be a country boundary). It is assumed that porosity mapping is part of the equity determination. In the first map the drawing of the iso-porosity lines has been carried out by simple triangulation. This appears to be the most 'objective' approach, especially if it is entrusted to the computer, which may be assumed to be 'impartial' as the programme obviously must be approved by all parties.

Even so, a considerable area of uncertainty remains between the outermost control points and the block boundaries (faults, OWC). Some procedure will have to be worked out in negotiations to solve the problem of how to draw the iso-porosity lines in this area 'equitably'.

The two highest porosity values happen to lie in the western area. Using the triangulated map it is obvious that the average porosity in this area will work out higher than that in the eastern area: this means a loss of equity for the owner of the eastern block. The second map is based on geological study of the well data from which it is concluded that most of the sand is of barrier type; the barrier bar is intersected by a channel-type sand of coarser grainsize and higher porosity. There is good reason to assume that the channel sand is not confined to the western block, where it has been found in two wells: why should the channel end just at the concession boundary? If indeed the channel is also present in the eastern block, the average porosity in this block would be higher than was concluded from the triangulated map and, consequently, the equity for the easterrn block would also be higher. It seems obvious that Company West will favour the 'objective' triangulation method, but that on the contrary Company East will prefer the 'interpretative' method.

The fundamental problem is that it is impossible in practice to estimate oil-in-place with a smaller margin or error than at least a few percent. But each percentage point in equities is equivalent to considerable amounts of money. It is not uncommon that after the geologists and engineers have completed their laborious efforts to arrive at an equitable solution, a difference of a few percents remains; this then may have to be resolved by direct negotiation of the respective managements.

Chapter J

FIELD REVIEW STUDY

J.1 PRINCIPLES

In a developing field a new well is drilled. It is very rare in practice that such a well is entirely 'according to prognosis'; in other words, that it encounters the geological conditions exactly as they had been drawn by the production geologist. For example: the top of the reservoir is found a few tens of feet higher or lower than had been prognosed or a fault which should have been penetrated at a certain depth is not encountered at all.

In many cases such deviations from the existing geological picture of the field can be incorporated in that picture with minor adjustments of contours and fault positions in the immediate vicinity of the new well. However, as development proceeds and more and more of such adjustments are made, the geological picture eventually has been tampered with so much that it loses coherence and becomes geologically improbable. It is no longer the 'best possible picture'.

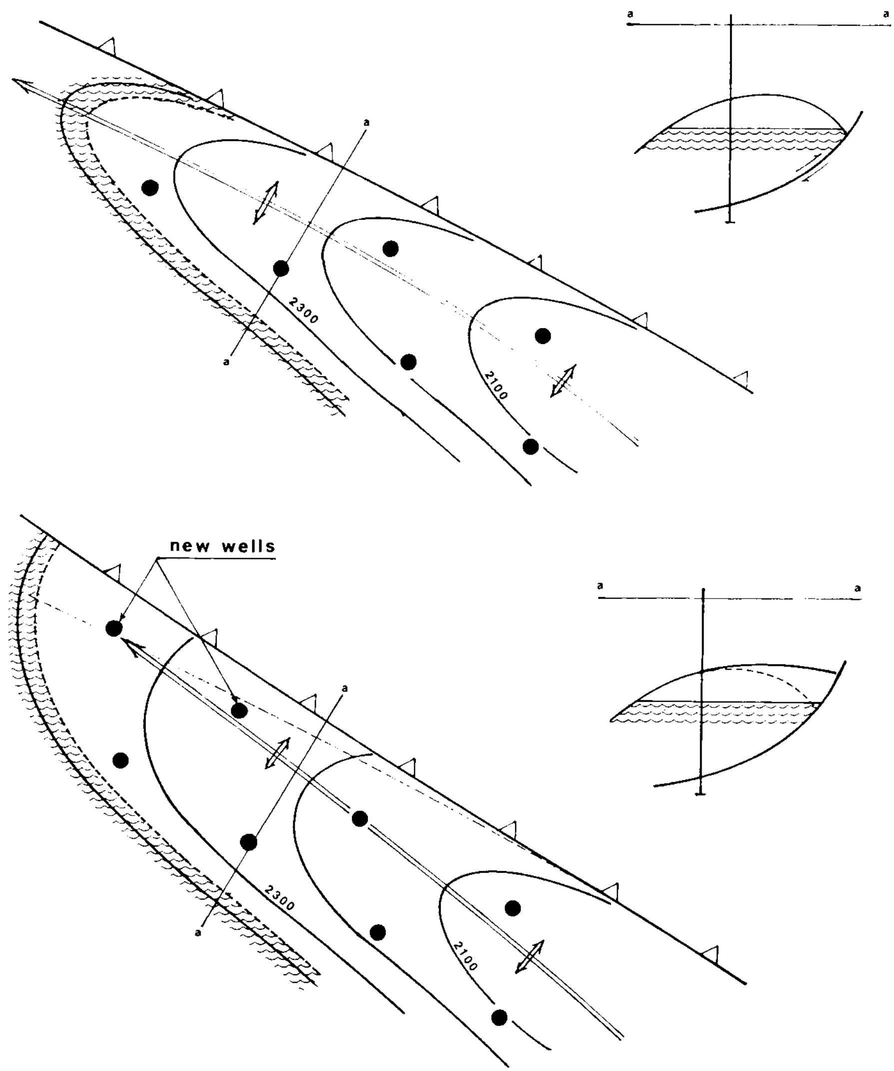
The time has then come for a complete geological review of the field. If this study is to be carried out to best advantage, it should start 'from scratch', i.e. with a thorough reworking of the correlation of all the wells, and then proceed through the entire procedure of a field study as outlined in Chapters B to F.

Such a study may take several months to complete but, considering the investments involved in developing a field, the expenditure for a few months of a geologist's and a geophysicist's time is small and easily justified.

Such a putting up-to-date of the entire geological picture in many cases leads to thorough revisions of the development plan. But, in addition, there is also a good chance that in the process of the study additional reserves are encountered. These may be either in entirely new structural units (comp.Section G.6) or because known reservoirs prove to be more extensive than had been foreseen. These are amongst the few occasions where the production geologist may actually 'find oil'.

J.2 RESULTS

RESERVES GAINED



The diagrams illustrate a case in which a field review resulted in both additional reserves and in a consequent revision of the drilling plans.

The gradual westward outstepping from the main area of the field was thought to have been completed when the wells shown in the upper figure had been drilled. The reservoir volume available for drainage was calculated to be too small to support a further continuation of the second line of wells.

The field review study suggested that the structural interpretation as adopted might be incorrect. It had been assumed that the anticlinal axis and the trace of the thrust fault would continue parallel to each other in northwesterly direction. But close analysis of the well data showed the alternative possibility of the axis and the fault trace converging. As a result the anticline would gradually be transformed into a more or less monoclinal block, dipping away from the fault trace. If this interpretation were correct, the oil-bearing reservoir volume present would be larger and could support one or two additional wells. In the event the two wells were drilled and proved to be satisfactory producers.

The case is shown to illustrate how, during a field review, the combination of careful study of the data and imaginative thinking may lead to considerable gains in reserves for a very small investment. Managements should be well aware of this possibility and allow their production geologists sufficient time to carry out the careful studies required.

J.3 DOCUMENTATION

The production geological review study covers the entire procedure of the analysis and description of the field and its reservoirs. In the interest of communication with other members of the petroleum engineering staff and in order to leave a comprehensive record for future users, it is useful to enclose with the study a full set of working documents. Listed below are those documents which are likely to be suitable, which does not mean that they will all be required in all cases.

STRATIGRAPHY

(1) TYPE LOG
showing stratigraphy and marker system.

(2) CORRELATION CHART (= stratigraphic section)
showing stratigraphic variations, fault cut-outs, etc.

(3) CORRELATION TABLE
for recording purposes, possibly computerized.

TECTONICS

(4) STRUCTURAL SECTIONS
for dissection of structure and as basis for construction of structure maps.

(5) FAULT MAP
for analysis and recording of fault pattern and to assist in construction of structure maps.

(6) STRUCTURE MAPS
of structurally important levels; possibly at seismic reflectors.

(7) ISOCHORE MAPS
for structural growth analysis and reserve estimating.

RESERVOIR GEOLOGY

(8) LOG SHAPE MAP
for environmental analysis.

(9) CORE DESCRIPTION
graphic presentation of core study results.

(10) NET PERMEABLE THICKNESS MAPS
net sand thickness maps or sand percentage maps; showing rock type distribution; suitable for reserve estimating.

(11) FLOW CHANNEL DIAGRAMS
fence diagrams, horizontal sections or other drawings suitable for fluid flow prediction.

ACCUMULATION CONDITIONS

(12) PENETRATION CHART
determination of OWC, GOC; reservoir subdivision.

(13) INVENTORY OF HYDROCARBONBEARING INTERVALS
for record purposes; possibly computerized.

(14) HORIZON MAPS
structure maps on top reservoir and subreservoirs; preferably with well production data; for development planning purposes.

(15) RESERVE MAPS
various maps suitable for reserve estimating purposes; probably derived from (7), (10), (13) and (14).

EPILOGUE

In the first part of this book, we have followed the production geologist on his way from the raw, disconnected data to his completed image of the geology of the oilfield. In the process of correlation, he has learned to recognize and identify the significant horizons and intervals that will form the skeleton for all his further work. In the analysis and depiction of the tectonic structure of his field, he builds up his picture of the positions in space of these horizons; never a finished and immutable, but at least his best possible picture. He then concentrates on a smaller objective: the reservoirs; using such sedimentological data and background knowledge as he may obtain, he investigates the variations of the configuration of the pore space in the reservoir, to evaluate the quality of the reservoir rocks as a medium for storage and transport of hydrocarbons. To complete his picture of the field, he examines the properties of the fluids in the reservoir and their distribution over the available pore space.

In the second part, we have seen the geologist in the practical application of his specialized knowledge to the optimization of the process of oil and gas production. In the infancy of the oilfield he uses the scanty data then available to feel his way out over the structure, so as to gather the maximum of useful information with the minimum number of appraisal wells. When the preliminary picture of the field appears sufficiently reliable, he will offer it to his organization as the basis for the development plan. In the development phase he helps to select the optimum location for each subsequent well, being alert to the possible appearance of new facts requiring modifications of his image of the field's structure. He provides the engineers with information on the characteristics of the reservoirs, to aid in their calculations and planning, particularly of supplemental recovery operations. To the economists goes his contribution to the commercial optimization of the field's exploitation, mainly on the basis of his volumetric reserve estimates.

At intervals during the life of his field, the geologist will return to the basic data and again go through the entire study procedure, in order to ensure that his picture of the field is still 'the best possible' and that its implications are being taken into account properly in the practice of development operations.

From the substratum of reef debris grow, in solid splendour, the structures of the coral colonies. I hope to have provided, from the debris of a lifetime's experience in applied oilfield geology, a modest substratum of elementary knowledge from which can grow, equally splendid and solid, the field studies of a new generation of production geologists.

May their dryholes be few!

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