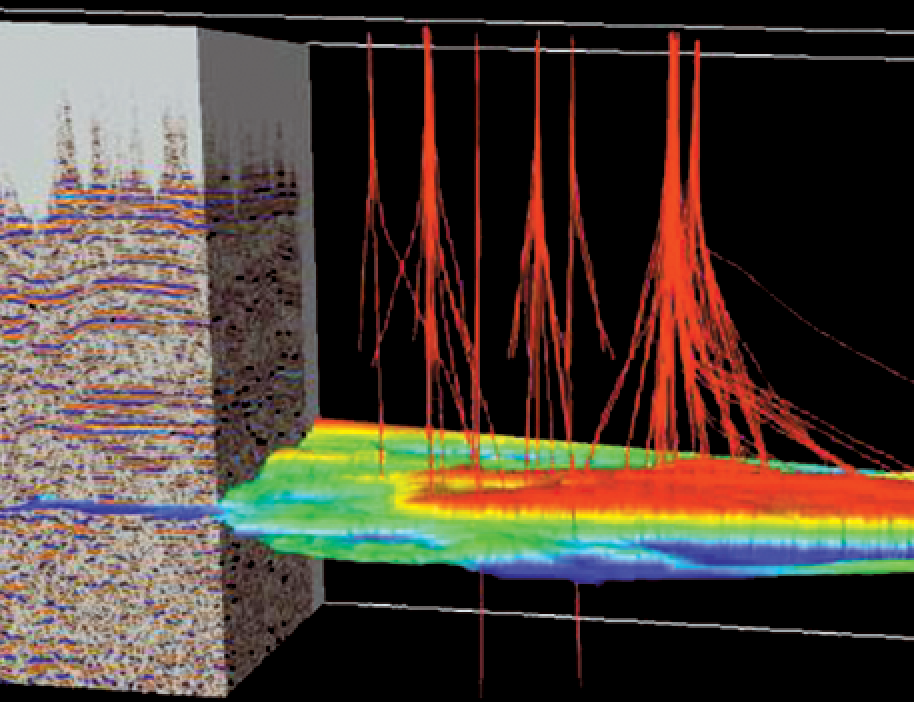
M. Bacon, R. Simm and T. Redshaw

3-D Seismic Interpretation



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3-D Seismic Interpretation

3-D seismic data have become the key tool used in the oil and gas industry to understand the subsurface. In addition to providing excellent structural images, the dense sampling of a 3-D survey can sometimes make it possible to map reservoir quality and the distribution of oil and gas. The aim of this book is to help geophysicists and geologists new to the technique to interpret 3-D data while avoiding common pitfalls.

Topics covered include basic structural interpretation and map-making; the use of 3-D visualisation methods; interpretation of seismic amplitudes, including their relation to rock and fluid properties; and the generation and use of AVO and acoustic impedance datasets. Also included is the increasingly important field of time-lapse seismic mapping, which allows the interpreter to trace the movement of fluids within the reservoir during production. The discussion of the acquisition and processing of 3-D seismic data is intended to promote an understanding of important data quality issues. Extensive mathematics has been avoided, but enough detail is included on the effects of changing rock and fluid properties to allow readers to make their own calculations. This new paperback edition also includes an extra appendix presenting material that brings the book fully up to date – including novel acquisition design, pore pressure prediction from seismic velocity, elastic impedance inversion, and time lapse seismics.

3-D Seismic Interpretation is an indispensable guide for geoscientists learning to use 3-D seismic data, particularly graduate students of geophysics and petroleum geology, and new entrants into the oil and gas industry.

Mike Bacon was awarded a Ph.D. in geophysics from the University of Cambridge before becoming a Principal Scientific Officer at the Institute of Geological Sciences in Edinburgh (now the British Geological Survey). After working as a lecturer in the Geology Department of the University of Accra, Ghana, he took a position with Shell UK where he worked for 19 years as a seismic interpreter and as team leader in seismic special studies. He now works for Petro-Canada UK as a geophysical advisor. Dr Bacon is a co-author of *Introduction to Seismic Interpretation* by McQuillin *et al.* (1979) and is a member of the editorial board of the petroleum industry magazine *First Break*. He is a Fellow of the Geological Society and a member of the EAGE (European Association of Geoscientists and Engineers).

Rob Simm is a geophysicist with 16 years' experience in the oil and gas industry and a specialist in the rock physics interpretation of seismic data in both exploration and production. After gaining an M.Sc. and Ph.D. in marine geology at University College London, the early part of his career was spent with Britoil plc and Tricentrol plc as a seismic interpreter. He subsequently took a position at Enterprise Oil and progressed from North Sea exploration to production and equity determination, prior to becoming an internal consultant to asset teams and management. Since 1999 Dr Simm has provided independent consultancy and training services to numerous independent and multi-national oil companies through his company Rock Physics Associates Ltd.

Terry Redshaw gained a Ph.D. in numerical analysis from the University of Wales before becoming a Geophysical Researcher with Western Geophysical. Since 1985 he has been employed by BP in a variety of roles. These have included research into imaging and inversion algorithms, as well as leading a team supplying BP's worldwide assets with support in the areas of seismic modelling, rock properties, AVO and seismic inversion. Dr Redshaw works at present in BP's Exploration Excellence team, which helps operating units to carry out the technical work needed to evaluate oil prospects and decide whether to drill them or not.

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Contents

Preface

Applied geophysics uses a large number of methods to investigate the subsurface. Because of its ability to produce images down to depths of thousands of metres with a resolution of tens of metres, the seismic method has become by far the most commonly used geophysical method in the oil and gas industry. In the past 20 years, the quality of seismic information has been greatly improved by the use of 3-D seismic methods. However, extracting useful information from seismic images remains the interpreter's craft skill, in which elements of geological and geophysical knowledge are combined in varying proportions. This book is intended for people beginning to develop that skill, either as part of a University course or at the beginning of a career in the oil and gas industry. It assumes that the reader has some general background knowledge of the seismic method. There are several excellent texts that cover the whole range of theory and practice (for example, R. E. Sheriff & L. P. Geldart, *Exploration Seismology* (2nd edn, 1995), Cambridge University Press). Our intention is not to replace these volumes, but rather to concentrate on the techniques of interpretation that are specific to 3-D seismic, or are greatly improved in usefulness by applying them to 3-D datasets (such as amplitude studies, AVO analysis, inversion and time-lapse seismic). However, there is enough explanation of the underlying principles to make the book fairly self-contained. In particular, the acquisition and processing of 3-D seismic data are described in some detail. This is partly because the interpreter needs to understand the limitations of his or her data, and whether misleading artefacts are likely to exist in the images that reach his or her desk. Also, he or she will sometimes need to interact with specialists in acquisition and processing, so should understand something of their specialised language. Bearing in mind the diversity of academic background among potential readers, we have avoided any extensive use of mathematics.

The range of topics that might be included is large, and we have tried to concentrate on those that are of most practical application in the authors' experience. There have been rapid advances in interpretation techniques over the past decade. In part this reflects the availability of more computer power at the desktop, so that first-pass interpretations can now often be made in days rather than months. At the same time, data quality has been improving, so that a wealth of detailed subsurface information can be extracted if the right methods are used. We have tried to portray the current state of the art in both these respects. The combination of the interpreter's ingenuity with even more computer power will surely lead to further developments in the future.

We have included a number of examples of seismic displays to illustrate the various interpretation techniques, and to give the reader a feeling for the typical quality of modern seismic data. We are grateful to the following for permission to reproduce proprietary or copyright material: BP Exploration for figs. 2.2, 2.8, 2.16, 2.23–2.24, 2.27, 2.30, 2.34–2.37, 8.3 and 8.7–8.8; ChevronTexaco and Statoil for fig. 5.12; Shell UK Exploration and Production for figs. 3.1, 3.3, 3.5–3.6, 3.8–3.13, 3.17–3.18, 3.20–3.24, 4.4, 4.6, 5.6, 6.2–6.8 and 6.10; the Wytch Farm partnership (BP Exploration Operating Co Ltd, Premier Oil plc, Kerr McGee Resources (UK) Ltd, ONEPM Ltd and Talisman North Sea Ltd) for figs. 7.1–7.6; the Geological Society of London and Dr R. Demyttenaere for fig. 1.6(b); the McGraw-Hill Companies for fig. 5.3; the European Association of Geoscientists and Engineers (EAGE) and Dr J. Hendrickson for fig. 5.16; the EAGE and Dr P. Hatchell for figs. 8.4–8.5; the EAGE and Dr J. Stammeijer for fig. 8.6; the Society of Exploration Geophysicists (SEG) for fig. 4.1, the SEG and Dr S. M. Greenlee for fig. 1.6(a), the SEG and Professor G. H. F. Gardner for fig. 5.1, the SEG and Dr H. Zeng for fig. 4.7, the SEG and Dr W. Wescott for fig. 4.8, and the SEG and Dr L. J. Wood for fig. 4.9. Figures 3.1, 3.3 and 3.24 were created using Landmark Graphics software, fig. 4.6 using Stratimagic software (Paradigm Geophysical), fig. 5.15(b) using Hampson–Russell software and fig. 6.3 using Jason Geosystems software.

The text is intended as an aid in developing understanding of the techniques of 3-D interpretation. We have not been able to include all the possible limitations on applicability and accuracy of the methods described. Care is needed in applying them in the real world. If in doubt, the advice of an experienced geophysicist or geologist should always be sought.

1 Introduction

If you want to find oil and gas accumulations, or produce them efficiently once found, then you need to understand subsurface geology. At its simplest, this means mapping subsurface structure to find structures where oil and gas may be trapped, or mapping faults that may be barriers to oil flow in a producing field. It would be good to have a map of the quality of the reservoir as well (e.g. its thickness and porosity), partly to estimate the volume of oil that may be present in a given trap, and partly to plan how best to get the oil or gas out of the ground. It would be better still to see where oil and gas are actually present in the subsurface, reducing the risk of drilling an unsuccessful exploration well, or even following the way that oil flows through the reservoir during production to make sure we don't leave any more of it than we can help behind in the ground. Ideally, we would like to get all this information cheaply, which in the offshore case means using as few boreholes as possible.

One traditional way of understanding the subsurface is from geological mapping at the surface. In many areas, however, structure and stratigraphy at depths of thousands of feet cannot be extrapolated from geological observation at the surface. Geological knowledge then depends on boreholes. They will give very detailed information at the points on the map where they are drilled. Interpolating between these control points, or extrapolating away from them into undrilled areas, is where geophysical methods can be most helpful.

Although some use has been made of gravity and magnetic observations, which respond to changes in rock density and magnetisation respectively, it is the seismic method that is by far the most widely used geophysical technique for subsurface mapping. The basic idea is very simple. Low-frequency sound waves are generated at the surface by a high-energy source (for example a small explosive charge). They travel down through the earth, and are reflected back from the tops and bases of layers of rock where there is a change in rock properties. The reflected sound travels back to the surface and is recorded by receivers resembling microphones. The time taken for the sound to travel from the source down to the reflecting interface and back to the surface tells us about the depth of the reflector, and the strength of the reflected signal tells us about the change of rock properties across the interface. This is similar to the way a ship's echo sounder can tell us the depth of water and whether the seabed is soft mud or hard rock.

Initially, seismic data were acquired along straight lines (2-D seismic); shooting a number of lines across an area gave us the data needed to make a map. Again, the process is analogous to making a bathymetric map from echo soundings along a number of ship tracks. More recently, it has been realised that there are big advantages to obtaining very closely spaced data, for example as a number of parallel straight lines very close together. Instead of having to interpolate between sparse 2-D lines, the result is very detailed information about the subsurface in a 3-D cube (x and y directions horizontally on the surface, z direction vertically downwards but in reflection time, not distance units). This is what is known as 3-D seismic.

This book is an introduction to the ways that 3-D seismic can be used to improve our understanding of the subsurface. There are several excellent texts that review the principles and practice of the seismic method in general (e.g. Sheriff & Geldart, 1995). Our intention is to concentrate on the distinctive features of 3-D seismic, and aspects that are no different from the corresponding 2-D case are therefore sketched in lightly. The aim of this first chapter is to outline why 3-D seismic data are technically superior to 2-D data. However, 3-D seismic data are expensive to acquire, so we look at the balance between better seismic quality and the cost of achieving it in different cases. The chapter continues with a roadmap of the technical material in the rest of the book, and concludes with notes on some important details of the conventions in use for displaying seismic and related data.

A complementary view of 3-D seismic interpretation, with excellent examples of colour displays, is provided by Brown (1999).

1.1 Seismic data

The simplest possible seismic measurement would be a 1-D point measurement with a single source (often referred to as a *shot*, from the days when explosive charges were the most usual sources) and receiver, both located in the same place. The results could be displayed as a seismic trace, which is just a graph of the signal amplitude against travel-time, conventionally displayed with the time axis pointing vertically downwards. Reflectors would be visible as trace excursions above the ambient noise level. Much more useful is a 2-D measurement, with sources and receivers positioned along a straight line on the surface. It would be possible to achieve this by repeating our 1-D measurement at a series of locations along the line. In practice, many receivers regularly spaced along the line are used, all recording the signal from a series of source points. In this case, we can extract all the traces that have the same midpoint of the source–receiver offset. This is a *common midpoint gather* (CMP). The traces within such a CMP gather can be added together (*stacked*) if the increase of travel-time with offset is first corrected for (*normal moveout* (*NMO*) *correction*). The details of this process are discussed in chapter 2.

The stacked trace is as it would be for a 1-D observation, with coincident source and receiver, but with much improved signal to noise ratio. These traces can then be displayed as a *seismic section*, in which each seismic trace is plotted vertically below the appropriate surface point of the corresponding 1-D observation. The trace spacing depends on the spacing of shots and receivers, but might be 12.5 or 25 m for a typical survey. The seismic section is to a first approximation a cross-section through the earth, though we need to note several limitations.

(1) The vertical axis is the time taken for seismic waves to travel to the reflector and back again (often called the *two-way time, TWT*), not depth.

(2) The actual reflection point in the subsurface is not necessarily vertically below the trace position, if the subsurface reflectors are dipping. We can try to reposition the reflection to the correct trace location so that the cross-section is closer to the real subsurface structure, but this is only in part possible for a 2-D line (see section 1.2).

(3) For a subsurface interface to generate a reflection, there has to be a change across it of a quantity called *acoustic impedance* (which is the product of density and seismic velocity in the layer concerned), so that not all interfaces of geological significance are necessarily visible on seismic data. The seismic velocity is the velocity with which seismic waves (see the glossary in Appendix 2) travel through the rock.

(4) The vertical resolution of the section, which is discussed further in chapter 4, is likely to be at best 5 ms. (TWT is usually expressed in milliseconds (ms): 1 ms = 1/1000 s.) Despite all this, the 2-D section gives considerable insight into the geometry of the subsurface.

Although not necessarily acquired in this way, a simple way of thinking of 3-D data is as a series of closely spaced parallel sections. The spacing between these sections might be the same 12.5 or 25 m as the typical trace spacing within each section. There are two benefits to be derived from the 3-D coverage:

(a) correcting for lateral shifts of reflection points in 3-D rather than 2-D produces a better image of the subsurface,

(b) the very dense data coverage makes it much easier and less ambiguous to follow structural or stratigraphic features across the survey area.

We shall discuss each of these in turn.

1.2 Migration of seismic data

The process of transforming the seismic section to allow for the fact that the reflection points are laterally shifted relative to the surface source/receiver locations is known as seismic *migration*. For a 2-D section, fig. 1.1 shows how the problem arises. We assume that the data as recorded have been transformed (as discussed above) to what would be observed in the *zero-offset* case, i.e. with source and receiver coincident and therefore no offset between them. For zero-offset, the reflected ray must retrace the

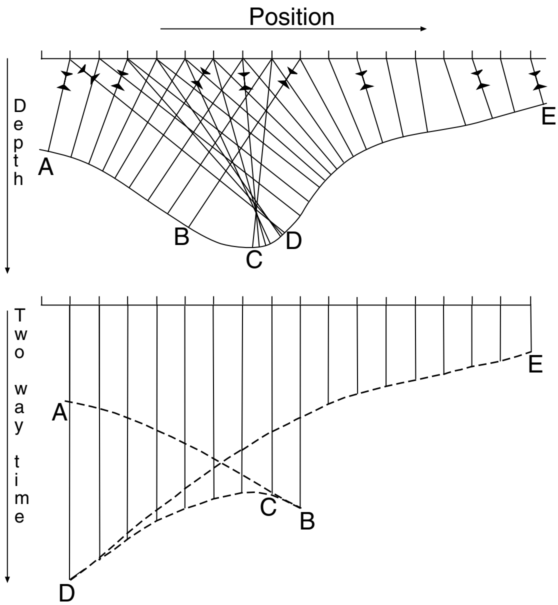


Fig. 1.1 Sketch of normal-incidence rays and resulting time section.

path of the incident ray to the reflector, so the angle of incidence at the reflecting horizon must be 90°. Not only are reflection points not directly below the surface point wherever this horizon is dipping, but for some surface locations there may be several different reflections from the horizon, and for other surface locations there may be no reflections received at all. The display produced by plotting seismic traces vertically below the surface points will, as sketched in the lower half of fig. 1.1, be hard to interpret in any detailed sense. This problem is solved by a processing step called *migration*, which repositions reflectors to their correct location in space. There are various ways of carrying this out in practice, but the basis of one method (*Kirchhoff summation*) is illustrated in fig. 1.2. This shows a point scatterer in a medium of uniform velocity; this reflector is to be thought of as a 'cat's eye' that reflects any incident ray directly back along the path by which it arrived. If a seismic line is shot above such a reflector, it appears on the resulting section as a hyperbolic event. This suggests a migration method as follows. To find the amplitude at a point A in the migrated section, the hyperbola corresponding to a point scatterer at A is superimposed on the section. Wherever it crosses a trace, the amplitude value is noted. The sum of these amplitudes gives the amplitude at A in the migrated section. Of course, not all the amplitude values in the summation truly relate to the scatterer at A; however, if there are enough traces, energy received from other scatterers will tend to cancel out, whereas energy truly radiated from A will add up in phase along the curve. (A more complete discussion shows that various corrections must be applied before the summation, as explained, for example, in Schneider, 1978.)

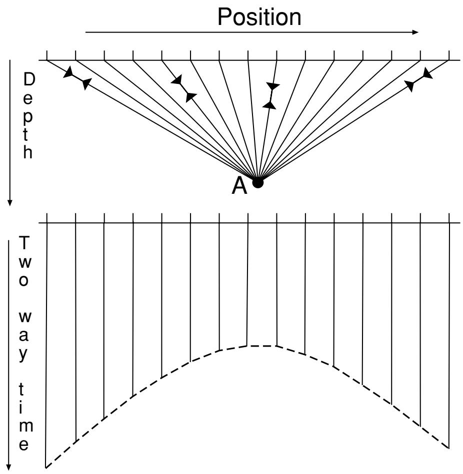


Fig. 1.2 Sketch of rays reflected from a point scatterer and resulting time section.

The snag with such a procedure is that it repositions data only within the seismic section. If data were acquired along a seismic line in the dip direction, this should work fairly well; if, however, we acquire data along a line in the strike direction, it will not give correct results. If we have a 2.5-D structure, i.e. a 3-D structure in which the dip section is the same at all points along the structure, then on the strike section all reflectors will be horizontal, and the migration process will not reposition them at all. After migration, dip and strike sections will therefore not tie at their intersection (fig. 1.3(a)). This makes interpretation of a close grid of 2-D lines over a complex structure very difficult to carry out, especially since in the real world the local dip and strike directions will change across the structure.

In general, some of the reflections on any seismic line will come from subsurface points that do not lie directly below the line, and migrating reflections as though they do belong in the vertical plane below the line will give misleading results. For example, fig. 1.3(b) shows a sketch map of a seismic line shot obliquely across a slope. The reflection points are located offline by an amount that varies with the local dip, but is typically 250 m. If we see some feature on this line that is important to precise placing of an exploration well (for example a small fault or an amplitude anomaly), we have to bear in mind that the feature is in reality some 250 m away from the seismic line that shows it. Of course, in such a simple case it would be fairly easy to allow for these shifts by interpreting a grid of 2-D lines. If, however, the structure is complex, perhaps with many small fault blocks each with a different dip on the target level, it becomes almost impossible to map the structure from such a grid.

Migration of a 3-D survey, on the other hand, gathers together energy in 3-D; Kirchhoff summation is across the surface of a hyperboloid rather than along a hyperbola (fig. 1.4). Migration of a trace in a 3-D survey gathers together all the reflected energy that belongs to it, from all other traces recorded over the whole (x, y) plane. This

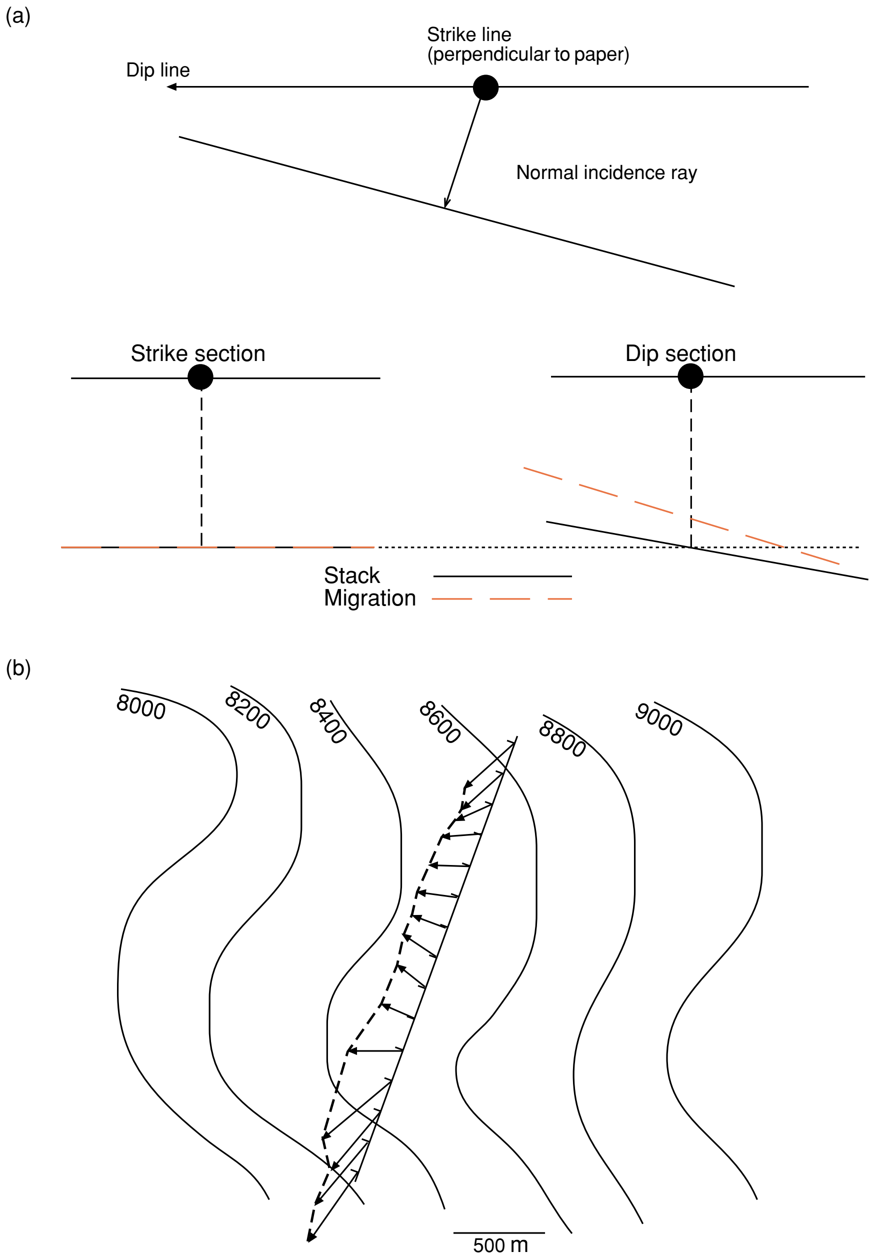


Fig. 1.3 (a) For a 2.5-D structure, dip and strike lines do not tie after migration; (b) map view of reflection points for a 2-D line (contours are depth in feet (ft)).

means that events are correctly positioned in the 3-D volume (provided that the migration process has been carried out with an accurate algorithm and choice of parameters, as discussed further in chapter 2). This is an enormous advance for mapping of complex areas; instead of a grid of lines that do not tie with one another, we have a

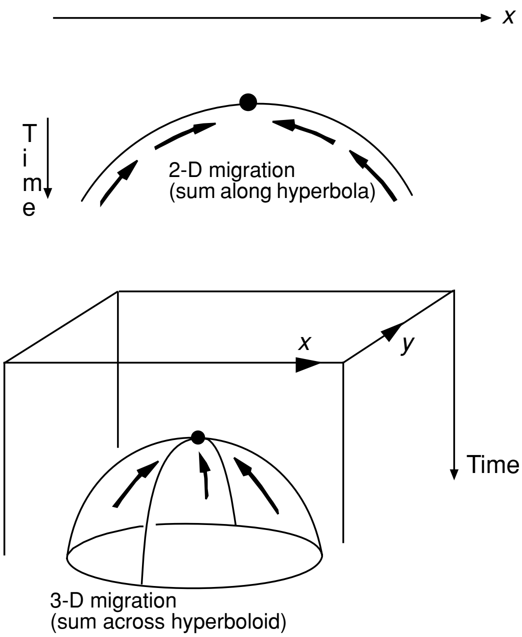


Fig. 1.4 Kirchhoff migration in 2-D and 3-D.

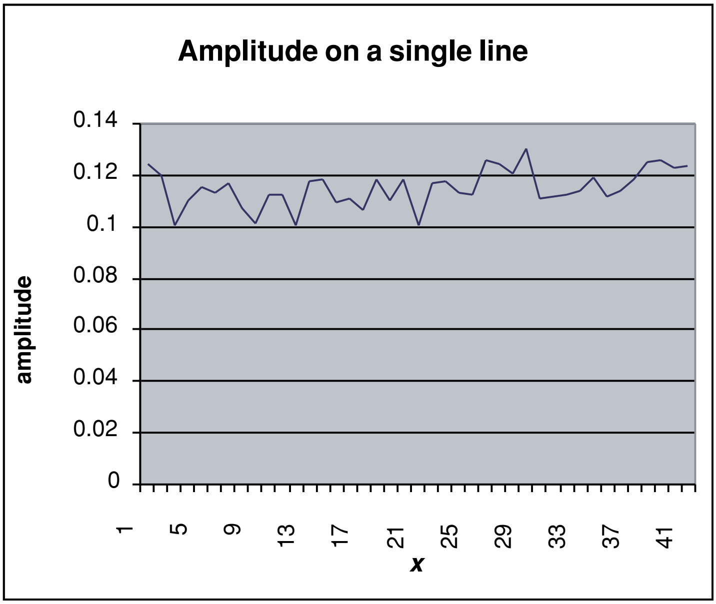
volume of trace data, from which sections can be chosen for display in any orientation we want. Furthermore, focussing of the data is also improved. For unmigrated data, the limiting horizontal resolution can be taken as the size of the Fresnel zone, an area surrounding any point on the reflector from which reflected energy arrives at the receiver more or less in phase and thus contributing to the signal at that reflection point. The radius f of this zone is given approximately by

$$f^2 = \frac{\lambda h}{2},$$

where λ is the dominant wavelength of the seismic disturbance and h is the depth of the reflector below the source–receiver point (see e.g. McQuillin *et al.*, 1984). This can amount to several hundred metres in a typical case. Migration collapses the Fresnel zones; 2-D migration collapses the zone only along the line direction, but 3-D migration collapses it in both inline and crossline directions, to a value approaching $\lambda/2$, which may amount to a few tens of metres. This will improve the detail that can be seen in the seismic image, though various factors will still limit the resolution that can be achieved in practice (see section 4.1).

1.3 Data density

When 3-D seismic first became available, it resulted in an immediate increase in the accuracy of subsurface structure maps. This was partly because of the improved imaging



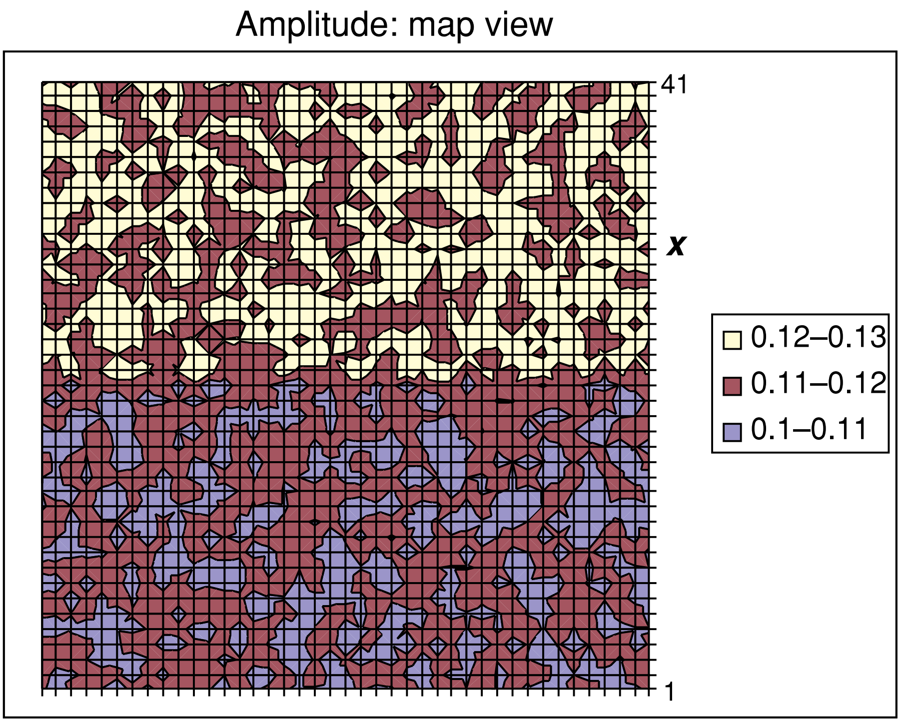


Fig. 1.5 Top: graph of amplitude versus position along a single line. Bottom: map view of amplitude variation across many similar parallel lines.

discussed in the last section, but also because of the sheer density of information available. Mapping complex structures from a grid of 2-D data is a subjective process; the interpreter has to make decisions about how to join up features seen on lines that might be a kilometre or more apart. This means that establishing the fault pattern in a complicated area will be time-consuming, and the resulting maps will often have significant uncertainties. 3-D data, with their dense grid of traces, allow features such as faults or stratigraphic terminations to be followed and mapped with much greater assurance (see section 3.2.2).

More recently, it has been realised that the density of coverage allows us to make more use of seismic attributes. This will be discussed in detail in chapter 5, but a typical example might be that we measure the amplitude of a seismic reflection at the top of a reservoir, which increases when hydrocarbons are present. Such an effect is often quite subtle, because the amplitude change may be small and almost lost in the noise in the data. Consistent changes across a 3-D dataset stand out from the noise much more clearly than changes along a 2-D line.

Figure 1.5 shows a synthetic example illustrating the power of seeing dense data in map view. At the top is a graph of amplitude along a single line; the left-hand half has a mean value of 0.11 and the right-hand half of 0.12, and uniformly distributed random noise with amplitude $\pm$ 0.01 has been added. Working from this graph alone, it would be hard to be certain that there is a higher average amplitude over the right-hand part, or to say where the change occurs. The lower part of fig. 1.5 shows a contour map of the amplitudes of 40 such lines, each with the amplitude step in the same place but a different pattern of random noise; the lines run from bottom to top of the area. It is immediately obvious that there is a step change in average amplitude and that it occurs halfway up the area. As we shall see in chapter 5, correlation of amplitude anomalies with structure can be a powerful test for hydrocarbon presence; this synthetic example shows why interpretation of amplitude anomalies is much more solidly founded on 3-D data than on a grid of 2-D data.

1.4 Uses of seismic data

Seismic data are used both in exploration for oil and gas and in the production phase. The type and quality of data gathered are determined by the balance between the cost of the seismic and the benefit to be gained from it. The general pattern is as follows.

(1) Early exploration. At this stage, knowledge will probably be very sketchy, with little or no well information. The presence of a sedimentary basin may be inferred from outcrop geology, or indirectly from geophysical methods such as gravity and magnetics that distinguish sedimentary rocks from metamorphic basement on the basis of their density or magnetic susceptibility (see e.g. Telford *et al.*, 1976).