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978-0-521-71066-4 - 3-D Seismic Interpretation
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Excerpt
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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

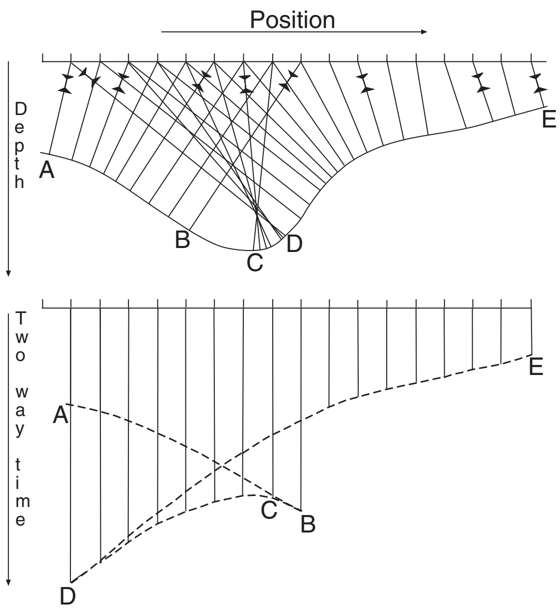

Fig. 1.1 Sketch of normal-incidence rays and resulting time section.

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.)

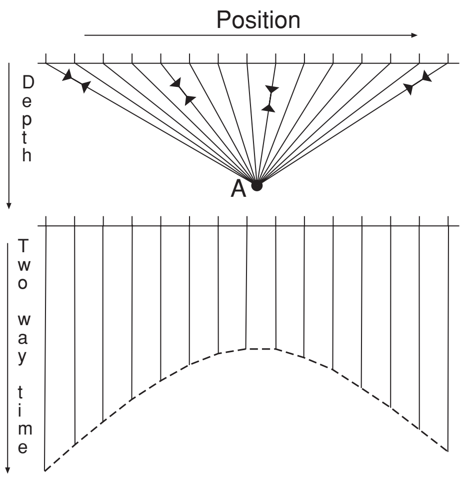

Fig. 1.2 Sketch of rays reflected from a point scatterer and resulting time section.

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

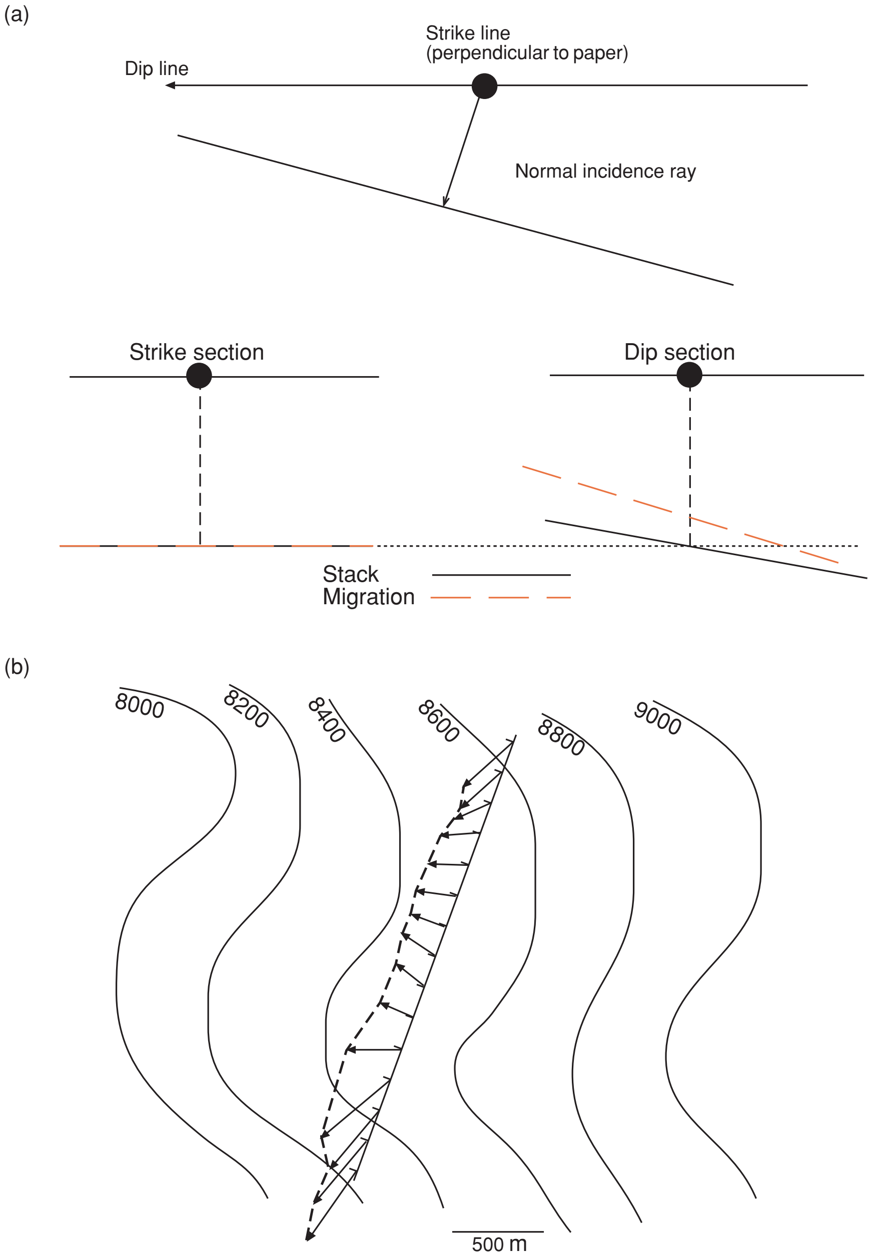

Fig. 1.3 (a) For a 2.5-D structure, dip and strike lines do not tie after migration; (b) map view of reflection points for a 2-D line (contours are depth in feet (ft)).

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

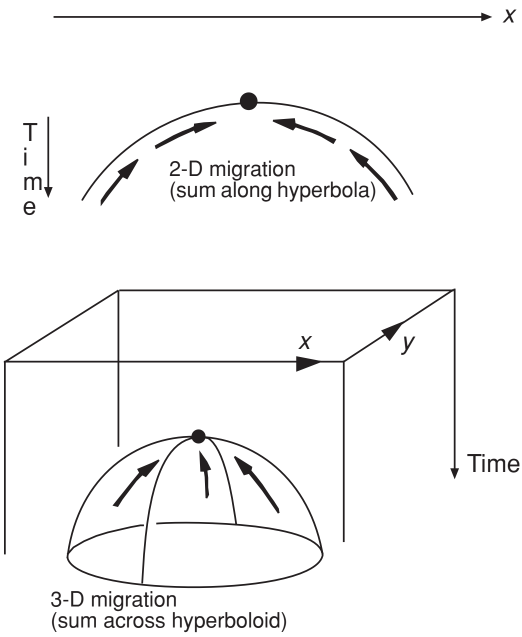

Fig. 1.4 Kirchhoff migration in 2-D and 3-D.

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

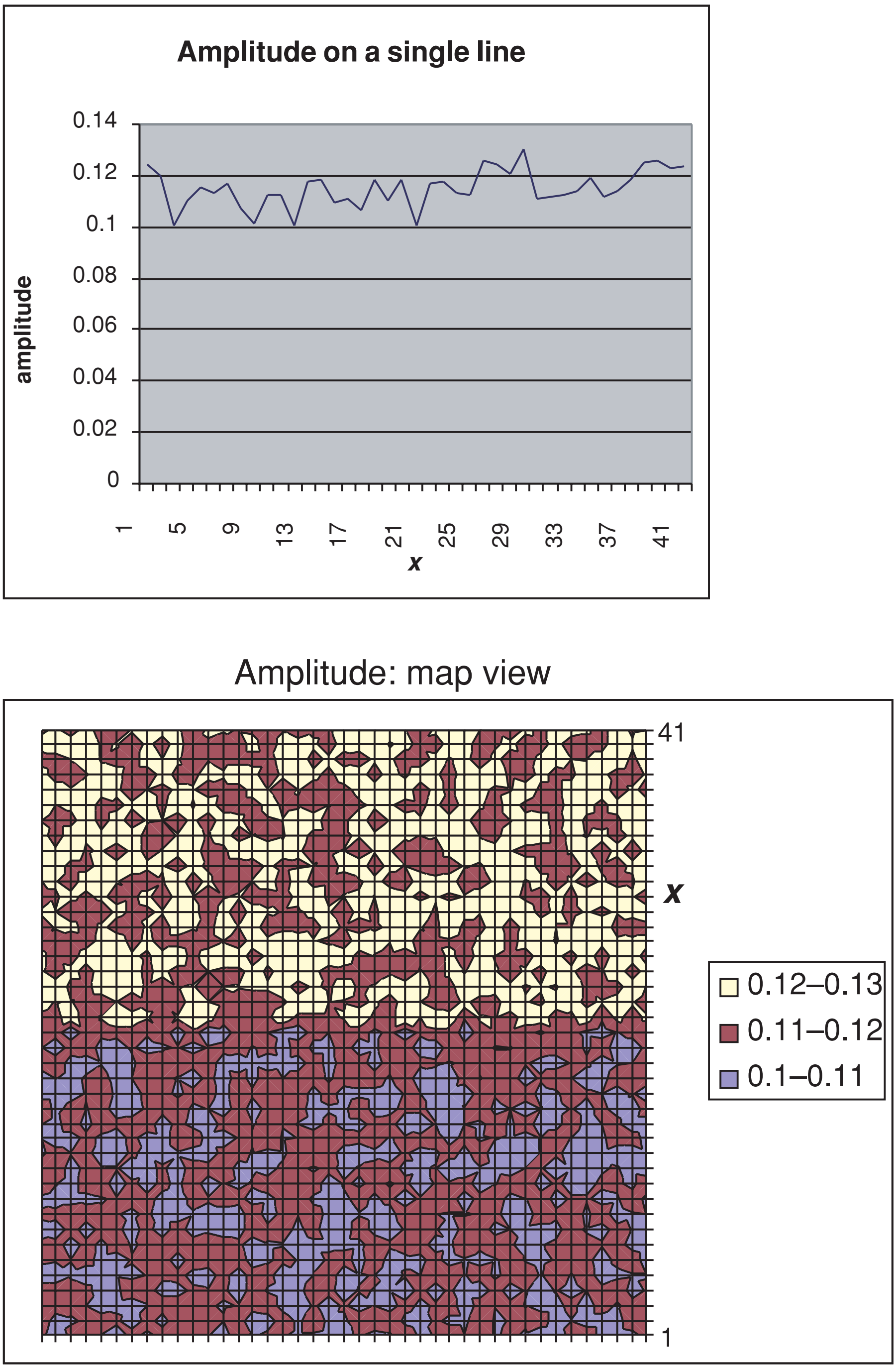

Fig. 1.5 Top: graph of amplitude versus position along a single line. Bottom: map view of amplitude variation across many similar parallel lines.

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).

At this stage even a small number of 2-D seismic profiles across the basin, perhaps tens of kilometres apart, will be very helpful in defining the general thickness of sediments and the overall structural style.

(2) Perhaps after some initial wells have been drilled in the basin with encouraging results, exploration moves on to a more detailed study, where the aim is to define and drill valid traps. More seismic data are needed at this stage, although the amount depends on the complexity of the structures. Simple anticlines may be adequately defined from a small number of 2-D profiles, but imaging of complex fault architectures will often be too poor on 2-D data for confident interpretation. If wells are fairly cheap and seismic data are expensive to acquire (as is often the case on land) it may be best to drill on the basis of a grid of 2-D lines. If wells are very expensive compared with seismic acquisition (the typical marine case), then it will already be worthwhile at this stage to use 3-D seismic to make sure that wells are correctly located within the defined traps. This might, for example, be a matter of drilling on the upthrown side of a fault, or in the correct location on a salt flank to intersect the pinchout of a prospective horizon. An example where 3-D seismic completely changed the structural map of a field is shown in fig. 1.6(a) (redrawn after Greenlee *et al*., 1994). This is the Alabaster Field, located on a salt flank in the Gulf of Mexico. The first exploration well was drilled on the basis of the 2-D map and was abandoned as a dry hole, encountering salt at the anticipated pay horizon. The 3-D survey shows that this well was drilled just updip of the pinchout of the main pay interval. This is a case where seismic amplitudes are indicative of hydrocarbon presence and are much easier to map out on 3-D seismic.

(3) After a discovery has been made, the next step is to understand how big it is. This is the key to deciding whether development will be profitable. At this stage, appraisal wells are needed to verify hydrocarbon presence and investigate reservoir quality across the accumulation. Detailed seismic mapping may reduce the number of appraisal wells needed, which will have an important impact on the overall economics of the small developments typical of a mature hydrocarbon province. The next step will be to plan the development. An example of the impact of 3-D on development planning is shown in fig. 1.6(b) (redrawn after Demyttenaere *et al*., 1993). This shows part of the Cormorant Field of the UK North Sea, where oil is trapped in Middle Jurassic sandstones in four separate westerly dipping fault blocks. The left-hand side of the figure shows the initial map of one of these fault blocks based on 2-D seismic data; the absence of internal structural complexity led to a development concept based on a row of crestal oil producers supported by downflank water injectors. The right-hand side of the figure shows the map of the fault block based on 3-D seismic; the compartmentalisation of the fault block led to a revised development plan with the aim of placing producer–injector pairs in each major compartment.