CHAPTER 10 The petroleum play

Ah! Vanitas vanitatum! Which of us is happy in this world? Which of us has his desire? or, having it, is satisfied? – Come, children, let us shut up the box and the puppets, for our play is played out.

(WILLIAM MAKEPEACE THACKERAY, *VANITY FAIR* (1848))

SUMMARY

A play is a perception or model of how a producible reservoir, petroleum charge system, regional topseal, and traps may combine to produce petroleum accumulations at a specific stratigraphic level. Prediction of source rocks, reservoirs, topseals, and traps requires an understanding of the structural and stratigraphic evolution of the depositional sequences within a basin. This understanding can be achieved through basin analysis, which serves as the platform for the assessment of petroleum plays. Correct identification and interpretation of the fundamental tectonic and thermal processes controlling basin formation, and the geometry and sedimentary facies contained in the basin-fill, is the first and most important step towards building the geological models that underpin play assessment.

The basic unit of petroleum resource assessment is the play, but the "petroleum system" concept is also a useful way for the practicing petroleum geologist to organize his/her investigations. A petroleum system comprises a pod of mature source rock and all of the migration paths, reservoir rocks, caprocks, and traps that can be charged by that source rock to produce oil and gas accumulations. Petroleum systems may be classified to help describe and predict the abundance, geographic location, and habitat of petroleum occurrences in a basin. This may be particularly useful in the ranking of relatively immature exploration provinces.

The first requirement for a play is that there is a *petroleum charge*. The petroleum charge system comprises source rocks, which must be capable of generating and expelling petroleum, and a migration pathway into the reservoir unit. Source rocks are sediments rich in organic matter derived from photosynthesizing marine or lacustrine algae and land plants which contain chemical compounds known as lipids. Lipids are preserved when sediments are deposited under anoxic conditions. Lakes, deltas, and marine basins are the main depositional settings of source beds.

Organic matter buried in sediments is in an insoluble form known as kerogen. Petroleum is generated when kerogen is chemically broken down as a result of rising temperature. For typical rates of heating, a stage of oil generation at approximately 100–150 °C is followed by a stage of oil cracking to gas (150–180 °C) and finally by dry gas generation (150–220 °C). Petroleum expulsion probably occurs as a result of the build-up of overpressure in the source rock as a consequence of hydrocarbon generation. For lean (i.e., organic poor) source rocks, petroleum expulsion is probably very inefficient. Secondary migration carries expelled petroleum towards sites of accumulation, and is driven by the buoyancy of petroleum fluids relative to formation pore waters. Migration stops when the capillary pressure of small pore systems exceeds the upward-directed buoyancy force.

A further requirement for a play is a porous and permeable *reservoir rock*. Pore space enables the reservoir to act as a tank of hydrocarbons, and permeability provides the plumbing system by which the reservoir may be drained of its hydrocarbon content. In both carbonates and sandstones, reservoir quality depends on depositional environment and paleoclimate but is very strongly affected by diagenetic pathway. The nature of near-surface diagenesis is predictable from the position of the reservoir in a depositional sequence or parasequence. A number of scales of heterogeneity exist, from kilometer scale to microscopic, that affect the distribution of porosity and permeability in the gross reservoir unit. Particu-

lar basin tectonic settings have associated with them particular types of reservoir geometry and composition.

A *regional topseal* or caprock is needed to seal petroleum in the gross reservoir unit. The mechanics of sealing are the same as those that control secondary migration. The ideal caprock is of a fine-grained lithology, and is ductile and laterally persistent. Thickness and depth of burial do not appear to be critical. Two of the most successful reservoir–caprock associations are where marine shales transgress over gently sloping clastic shelves, and where sabkha evaporites regress over shallow-marine carbonate shelves.

The final requirement for the operation of a petroleum play is the presence of *traps*. Traps are local subsurface concentrations of petroleum and may be classified into structural, stratigraphic, and hydrodynamic traps. Structural traps represent the habitat of most of the world's already discovered petroleum, and are formed by tectonic, diapiric, and gravitational processes. Stratigraphic traps are those inherited from the original depositional morphology of, or discontinuities in, the basin-fill, or from subsequent diagenetic effects. Large volumes of undiscovered petroleum probably reside in stratigraphic traps, and owing to difficulties in detection, may remain so.

10.1 FROM BASIN ANALYSIS TO PLAY CONCEPT

Basin analysis is a platform for assessment of the undiscovered petroleum potential of an area. Assessments of this kind guide the exploration programs of the petroleum industry. An understanding of the distribution and evolution of depositional sequences and facies allows rational and realistic predictions to be made of petroleum source rocks, reservoir rocks, and caprocks – the building-blocks of a petroleum play. The associated structural development of the basin is primarily responsible for the formation of petroleum traps.

The bulk of subsurface information in a sedimentary basin is obtained from seismic reflection surveying and well log interpretation. These are both technologically fast-moving fields that are documented elsewhere. The reader is referred to Badley (1985) for a thorough description of seismic interpretation, and to Bacon et al. (2003) and Brown (1999) for 3-D methods. Rider (1996) provides a summary of well log interpretation.

Play concepts are founded on an understanding of the stratigraphic and structural evolution of the basin. The geological models upon which predictions of source, reservoir, and caprocks, and their evolution through time are based, are outcomes of this understanding. The validity of these models, and therefore of the plays that are generated from them, is dependent on a correct interpretation of the boundaries and overall *geometry* of the genetic stratigraphic units, systems tracts, and depositional sequences involved in the play, and on a correct interpretation of the *sedimentary facies* within these stratigraphic units. Basin analysis provides the means of making these interpretations.

The previous chapters of this book have shown that the location and overall form of megasequences and depositional sequences may be understood in terms of the mechanical processes of basin formation. Thus basins due to lithospheric stretching, flexure, mantle dynamics, and strike–slip deformation each exhibit characteristic locations, geometries, and evolutions that may be understood in terms of the controlling broad plate tectonic and mantle processes. Knowledge of the underlying basin-forming process also implies a particular tectonic and thermal development for the basin, which is an important input to the thermal modeling of potential source rock intervals.

Correct identification and interpretation of the megasequences present in a province is the first step towards building the geological models for play assessment. Each megasequence can be broken down into a series of depositional sequences and systems tracts representing discrete phases of the basin infill (§8.2). This information forms the basis for the prediction of source, reservoir, and caprocks.

The type, amount, and quality of data available will limit the confidence held in any stratigraphic interpretation. The goal is to achieve a reliable *chronostratigraphic* interpretation of a basin-fill, so that the distribution and nature of sedimentary facies may be understood in terms of geological processes operating at a specific time. The chronostratigraphic interpretation must, however, be built up from interpretations of lithostratigraphy, biostratigraphy, and seismic stratigraphy. Each of these on their own are potentially unreliable.

Lithostratigraphy is dependent on outcrop and well information. Lithostratigraphic boundaries tend to be diachronous, and may cause serious chronostratigraphic miscorrelations. Reliability is limited by low outcrop exposure, sparse well control, and our general inability to reliably determine lithology from seismic data. *Biostratigraphy* is again restricted to outcrop and well data. Environmental conditions at the time of deposition may strongly influence the existence and likelihood of preservation of sensitive fossil groups, and diagenesis/metamorphism may destroy important biostratigraphic information. Both lithostratigraphy and biostratigraphy provide important stratigraphic "fence-posts." It is only *seismic stratigraphy*, however, that provides the inter-well and inter-outcrop information that forms the "fences" of the stratigraphic interpretation. As a result, seismic stratigraphy has had an enormous impact on the interpretation of basin stratigraphy.

Miscorrelation of information, and misinterpretation of sedimentary facies, is a serious danger unless lithostratigraphic and seismostratigraphic interpretations are integrated. The confidence held in a stratigraphic interpretation may be assessed by considering the adequacy of each of the required data types – outcrop, well, and seismic data – in terms of both quantity and quality. Deficiencies in the data base must be recognized. Normally, more than one interpretation fits the observable data, each with different implications for petroleum plays. Each geological model carries an associated risk of not being valid. This is called *model risk*.

A *chronostratigraphic diagram* is a useful way of illustrating the relationships between sedimentary facies in a depositional sequence (Fig. 10.1). Combined with a sequence isopach map, the chronostratigraphic diagram may be used to make sedimentary facies predictions for the entire sequence. Given these sedimentary facies, the next step is to make predictions of potential source, reservoir, and caprocks. The thermal maturity of the source rock (Chapter 9, §10.3), and the presence and timing of traps must also be addressed (§10.6). There is a risk that these elements of the petroleum play do not exist, even though the geological model is valid. This additional element of risk is termed *conditional play risk*.

10.2 THE PETROLEUM SYSTEM AND PLAY CONCEPT

10.2.1 Play definition

A play may initially be defined as a perception or model in the mind of the geologist of how a number of geological factors might combine to produce petroleum accumulations at a specific stratigraphic level in a basin. These geological factors must be capable of providing the essential ingredients of the petroleum play, namely:

- A *reservoir unit*, capable of storing the petroleum fluids and yielding them to the well bore at commercial rates;
- a *petroleum charge system*, comprising thermally mature petroleum source rocks capable of expelling petroleum fluids into porous and permeable carrier beds, which transport them towards sites of accumulation (traps) in the gross reservoir unit;
- a *regional topseal* or *caprock* to the reservoir unit, which contains the petroleum fluids at the stratigraphic level of the reservoir;
- petroleum *traps*, which concentrate the petroleum in specific locations, allowing commercial exploitation;
- *the timely relationship* of the above four ingredients so that, for example, traps are available at the time of petroleum charge.

Thus, a play may further be defined as a family of undrilled prospects and discovered pools of petroleum that are believed to share a common gross reservoir, regional topseal, and petroleum charge system. A brief description of a play might be:

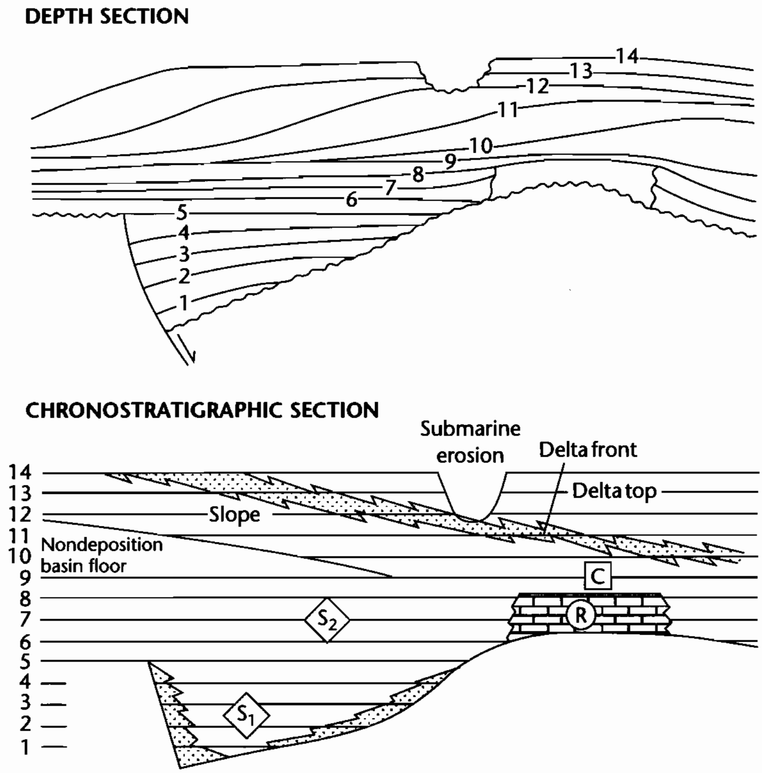
"Mid-Jurassic submarine fan sandstone reservoirs in Late Jurassic fault blocks, sealed by Lower Cretaceous marine mudstones, and charged during the Early Tertiary from Upper Jurassic marine source rocks (Fig. 10.2).

The geographical area over which the play is believed to extend is the *play fairway*. The extent of the fairway is determined initially by the depositional or erosional limits of the gross reservoir unit, but may also be limited by the known absence of any of the other factors. The mapping-out of the play fairway is discussed in §10.2.3.

A play may be considered *proven* if petroleum accumulations (pools or fields) are known to have resulted from the operation of the geological factors that define the play. These geological requirements are thus known to be present in the area under investigation, and the play may be said to be "working." In *unproven* plays, there is some doubt as to whether the geological factors actually do combine to produce a petroleum accumulation. One of the objectives of play assessment is to estimate the probability of the play working; this is known as *play chance*. Play chance combines model risk and conditional play risk into one factor.

10.2.2 The petroleum system

The basic unit of petroleum resource assessment is the play, but the "*petroleum system*" concept is also a useful way for the practising petroleum geologist to organize his/her investigations. The original work that gave birth to the



Time slice	Event
1–5	Growth faulting, onlap of basement high
5–6	Faulting ceases, fault overstepped, onlap of basement continues
6–8	Reef growth on basement high, surrounded by sediment-starved basin
9	Reef drowned
10–14	Delta progradation into current-swept basin, submarine channel erosion (12–14)

S Source rock

C Caprock or topseal

R Reservoir

Fig. 10.1 Schematic chronostratigraphic diagram, showing the relationships between sedimentary facies in a depositional sequence and the overall development of the basin.

petroleum system concept was carried out in the Williston basin of the USA (Dow and Momper 1972). Related concepts were subsequently described by Demaison (1984) (the *generative basin concept*), Meissner et al. (1984) (the *hydrocarbon machine*) and Ulmishek (1986) (the *independent petroliferous system*). The concept was subsequently defined more rigorously in Magoon and Dow (1994).

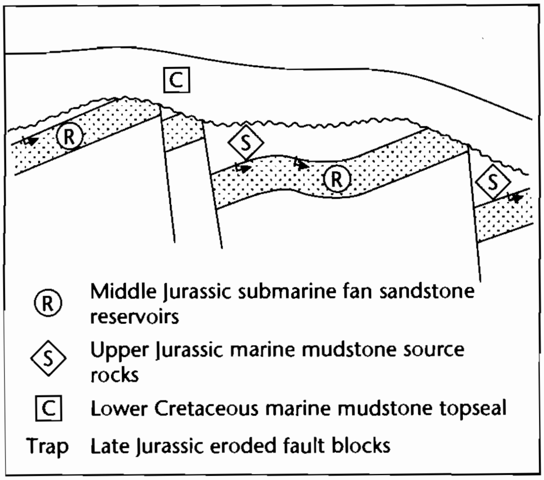


Fig. 10.2 Schematic illustration of a petroleum play. Plays must be carefully defined in terms of their reservoir, charge system, and regional topseal.

A petroleum system comprises a pod of mature source rock and all of the migration paths, reservoir rocks, caprocks, and traps that can be charged by that source rock to produce oil and gas accumulations. The concept, which has seen widespread practical application in the petroleum exploration industry since the mid-1990s, places the source rock as the first and foremost element of the geological system required to produce a petroleum play. When adopting this concept, the practising petroleum geologist goes through an assessment process that reflects the geological process of hydrocarbon generation, migration, and entrapment. By starting with the source rock, the petroleum system concept encourages the petroleum geologist to consider all the journeys and destinations of hydrocarbons generated and expelled from a source rock, and is more likely to stimulate ideas on new plays than an exploration approach strongly focused on one or two reservoirs that are already proven in the basin.

The petroleum system should be defined in terms of:

1 Its *stratigraphic* extent: in the system proposed by Magoon and Dow (1994), it takes its name from the source rock, qualified by the main reservoir rock that it charges. This linkage, between source and reservoir, may be: (i) *known* if the petroleum can be conclusively related to the source rock through oil-source or gas-source geochemical correlation, (ii) *hypothetical* if geochemical evidence indicates a source rock but a firm correlation has not been made, and (iii) *speculative* if based only on geological or geophysical evidence. An example is the Mandal–Ekofisk petroleum system of the North Sea described by Cornford (1994). The stratigraphic extent of the petroleum system should also reference the other essential elements, namely the carrier bed and caprock, and be illustrated by a cross-section drawn at the *critical moment* (defined in (3) below).

2 Its *geographic* extent, shown by a petroleum system map. This map shows the pod of active source rock, together with the associated discoveries, seeps, and shows, at the *critical moment* for the system. As part of the petroleum system documentation, a table of the discovered accumulations and their field sizes should be included.

3 Its *temporal* extent, illustrated by a burial history chart and events chart that shows the critical moment. The *critical moment* is the time at which most of the hydrocarbons were generated, migrated, and accumulated in the primary trap type. The events chart shows the time of deposition of the stratigraphic components of the system, and timing of key processes (trap formation, generation-migration, and entrapment) and the period over which trapped hydrocarbons are preserved, modified or destroyed.

A genetic classification of petroleum systems has been developed by Demaison and Huizinga (1994) to help describe and predict the abundance, geographic location and habitat of petroleum occurrences in a basin. This may be particularly useful in the ranking of relatively immature exploration provinces. This classification is based on three key factors that can be deduced from basin analysis and geochemical data (Fig. 10.3):

1 *Charge factor*: reflects the initial richness and volume of mature source rock, and is therefore a guide to the regional charge potential of the petroleum system. The Source Potential Index (SPI) combines source rock richness and source rock thickness into a single parameter that is known to be positively correlated (in well-explored petroleum provinces) with discovered petroleum reserves. Systems may be categorized into supercharged, normally charged, and undercharged. Charge factor is the single most important control on the petroleum richness of a system.

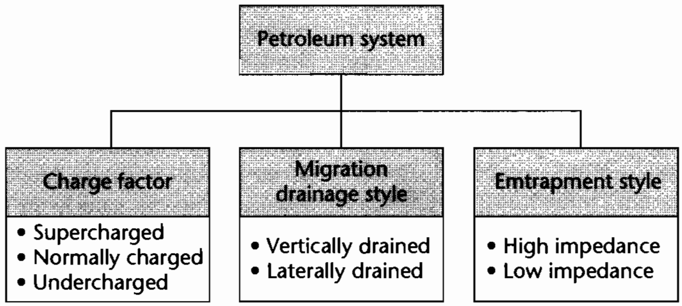


Fig. 10.3 Demaison and Huizinga's (1994) genetic classification of petroleum systems.

2 *Migration drainage style*: a reflection of the structure and stratigraphy of the basin-fill. Migration drainage style may be either dominantly vertical or dominantly lateral. A *vertical migration style* is assisted by faults and fractures that penetrate regional seals, or by reservoir and carrier beds that interconnect vertically over large distances, and is most common in rifted basins, sandy deltaic sequences, and in highly fractured fold and thrust belts. Examples are the North Sea and Gulf of Suez failed rifts, passive margin basins such as the Lower Congo Basin of Angola, the Campos Basin of Brazil, and the Barrow–Dampier Basin of NW Australia, and the Tertiary deltas of Nigeria and the US Gulf of Mexico. Traps ideally need to be located vertically above the mature pod of source rock in order to be charged. In supercharged, vertically drained petroleum systems, abundant surface seepage may occur, as in the San Joaquin Basin of California, the US Gulf Coast salt dome province, the Zagros fold–thrust belt of Iran, and the Magdalena Valley of Colombia. A *lateral migration style* is dominant in basins with extensive reservoir-seal couplets in tectonically stable settings, for example in foreland basins. Migration may be focused into arches or noses that plunge into the basin. Traps located along these focused migration routes may collect the charge from much of the source kitchen, while other areas are starved. Petroleum occurrences may be located long distances (several hundred km) away from the mature source pod. Excellent examples are the Oriente/Maranon Basin of Peru/Ecuador and the North Slope of Alaska. In supercharged, laterally drained petroleum systems, very large petroleum volumes may migrate as far as the shallow edges of the basin, as in the heavy oil provinces of western Canada (Athabasca) and eastern Venezuela (Orinoco).

3 *Entrapment style*: reflects the degree to which hydrocarbons are dispersed in moving from source rock to trap. Thermodynamic principles suggest that over geological time, natural geological processes work to ultimately disperse and destroy petroleum in sedimentary rocks. As petroleum migrates from source rock to its ultimate fate of destruction at the Earth's surface, local geological factors (trapping mechanisms) may resist this wholesale process, at least temporarily, and give rise to petroleum accumulations. Physical resistance to petroleum dispersion, or *impedance*, is largely a function of structural and stratigraphic complexity. A *low impedance entrapment style* indicates a tendency for hydrocarbons to flow efficiently along major migration routes with little resistance or dispersion, and occurs where good quality carrier beds and regional seals are continuous over large distances. Very large volumes of petroleum may be focused into relatively few ultimate sites of accumulation. A *high impedance entrapment style* is one in which hydrocarbon migration is dispersed by stratigraphic complexity or structural deformation into many different routes and sites of entrapment, at both the macro and micro scale. Large volumes of petroleum may be lost from commercial exploitation.

10.2.3 Definition and mapping of the play fairway

Play fairway maps show the geographical distribution of the key geological controls on the play fairway. These geological controls determine the presence of an effective reservoir, a petroleum charge into the reservoir, a regional topseal to the reservoir, the presence of traps, and the timely relationship of the above factors (§10.2.1).

A suite of maps showing the distribution of potential reservoir, source, and caprock facies can be drawn. Caprocks and sources may be external to the sequence containing the reservoir. As discussed in §10.2.2, a single source rock horizon may charge a number of separate reservoir-defined plays. A single reservoir-defined play may also be charged from a variety of separate source rock intervals. The objective of play assessment is to anticipate all of the possible combinations of potential reservoirs, sources and caprocks that may produce petroleum plays in the basin. For each reservoir-defined play, a single map can be produced that shows the distribution of the potential reservoir facies, the source "kitchen(s)" needed to charge the reservoir, and the potential caprock facies.

Demaison (1984) introduced the "generative basin concept," and described how petroleum generative kitchens could be mapped out. White (1988) extended this concept by including the reservoir, topseal, and trapping controls on the play.

Plays are essentially reservoir-defined. Hence, fairways at different stratigraphic levels in a basin may be stacked vertically. Within a single play, all prospects and discovered fields share a common geological mechanism for petroleum occurrence. Petroleum accumulations, discovered or undiscovered, within a single play fairway, can be considered to constitute a naturally occurring population or family of geological phenomena. Thus, each play can have a characteristic field size distribution and drilling success ratio.

In assessing an unproven play, the probability of the play working (play chance) should be estimated as part of the resource assessment process. Owing to the interplay of the critical geological factors over the extent of the fairway, it is normal for play chance to vary spatially. This variation in play chance may be due to hard evidence of adverse geology in different parts of the fairway (determined, for example, from well or seismic data), or to variations in the quantity or quality of the data base, which allows greater or lesser confidence in the interpretations made. As a result, an unproven fairway may be subdivided into a mosaic of segments (*common-risk segments*) – play chance may vary for each segment, but within a segment it is constant.

The fairway can also be subdivided into segments if there are strong reasons for believing field sizes are likely to be significantly different (for example, as a result of differing structural development in different parts of the fairway), or drilling success ratios are likely to vary significantly. Thus, the three factors that define fairway segments are variations in: (i) play chance, (ii) expected field sizes, or (iii) expected drilling success ratios. In this way, reservoir-defined plays are sometimes subdivided by trap type. Examples are the Kapuni Overthrust segment and the Kapuni Inversion segment of the Eocene Kapuni Coal Measures play of the Taranaki Basin, New Zealand.

The following items of geological information are contained on a play map (Fig. 10.4):

1 The depositional or erosional limits of the reservoir unit;
2 the distribution of reservoir facies within the gross reservoir unit;
3 the areas where a source rock is present;
4 the area where it is mature (the kitchen);
5 a migration zone around the kitchen; together with (4) it represents the area receiving a petroleum charge;
6 areas where there is an effective regional seal;
7 areas where traps are present (structural or stratigraphic);
8 oil and gas fields, dry holes, and untested prospects, leads and notional prospects;
9 drilling success ratios for specific parts of the fairway.

The drilling success ratio is the ratio of the number of *technical successes* to the number of *valid tests* of the fairway. A *technical success* is an exploration well that flows petroleum to surface or in which the presence of petroleum in drill-stem or wireline formation tests convincingly demonstrates the presence of a pool of recoverable petroleum. It carries no implication of commerciality. A *commercial success* is a well that discovers a petroleum accumulation that can be economically developed. A *valid test* is a well that penetrated the play fairway, and intended to test an exploration target in the play fairway. In basins with vertically stacked fairways, there may be many more penetrations of a fairway than there are valid tests. Valid tests are not only those wells that tested valid traps in the fairway.

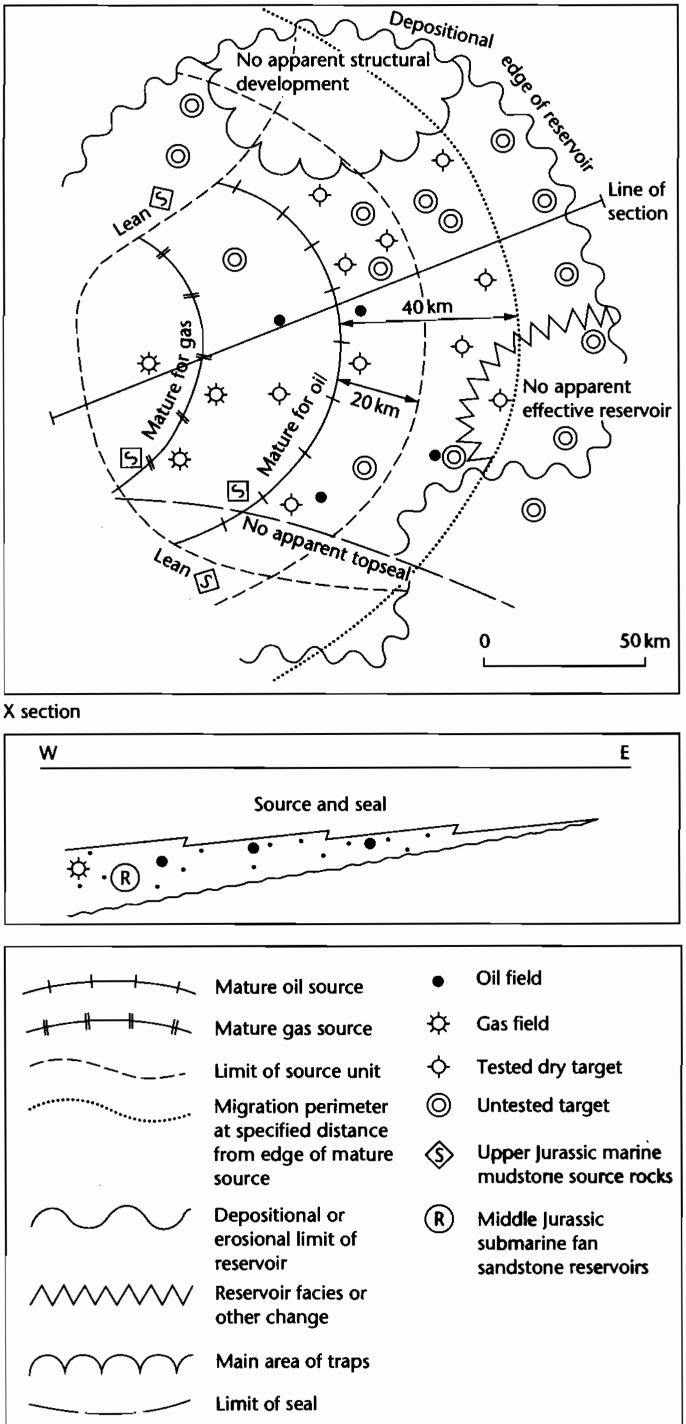


Fig. 10.4 Example of a play map (after White 1988). The play map should show all the important geological factors likely to control hydrocarbon accumulation in the fairway. The fairway is initially reservoir-defined, then the extent of the charge, topseal, and likely trap development are added.

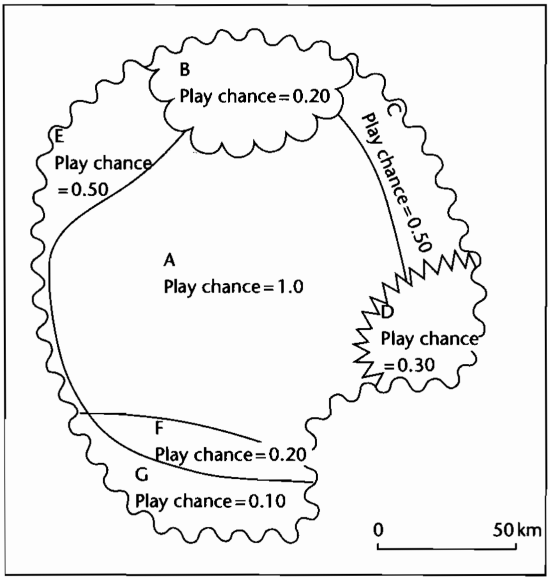


Fig. 10.5 Subdivision of the play fairway into common-risk segments. These are controlled by the distribution of reservoir charge, topseal, and likely trap development shown in Fig. 10.4. A play chance is assessed for each common-risk segment. In this illustration, segment A is considered already proven (play chance is 1.0).

There are normally far more dry holes than technical successes in a play. Within a proven play, dry holes are caused by local geological variations, such as the absence of a lateral seal in a faulted prospect, the existence of a migration shadow, or local diagenetic destruction of reservoir porosity. These factors contribute to *prospect-specific risk.*

In Figure 10.4, an area of mature source in the west of the area has experienced the highest drilling success ratio (75%). As we move outwards, firstly a migration distance of 20 km, and then a migration distance of 40 km, the success ratios drop to 28% and then 20%. This is interpreted to be caused by more and more prospects failing to lie on migration routes as the distance from the kitchen increases. Despite these variations in success ratio, however, the play is effectively proven in these areas. Beyond the 40 km migration perimeter, there are no existing discoveries and the play is unproven.

Common risk segment A is considered already proven (play chance of 1.0). The unproven part of the fairway is divided into the following common risk segments (Fig. 10.5):

- B: an area of no apparent structural development in the north (no traps). The seismic grid, however, is coarse and there may be stratigraphic traps, so the possibility of traps cannot be ruled out (play chance assessed at 0.20);
- C: an area beyond the 40 km migration perimeter in the east. Although unlikely, a very focused migration path could charge a prospect in this segment (play chance is assessed at 0.50);
- D: an area beyond the 40 km migration perimeter where reservoir effectiveness may be destroyed by diagenesis (play chance assessed at 0.30);
- E: an area in the northwest, up-dip from a lean source. However, the geochemical database is in fact quite poor and source rock interpretations unreliable (play chance is assessed at 0.50);
- F: an area in the south with no apparent topseal (play chance assessed at 0.20);
- G: an area in the south up-dip from a lean source and also with no apparent regional topseal (play chance assessed at 0.10).

Beyond the depositional or structurally controlled limits of the gross reservoir unit, there is no play at all. This is the outer limit of the fairway.

10.2.4 A note on resource assessment

Quantitative estimates of the undiscovered potential of plays are required by petroleum exploration companies in order to evaluate exploration investment opportunities and guide long-term strategic plans. Estimates of the likely size and timing of future discoveries, and hence future petroleum supply, also form an important element in the planning studies of government organizations.

A range of geological, geochemical, and statistical techniques has been developed over the years to estimate undiscovered resources. We have shown how play fairway maps indicate the key geological controls on the play. Further stages in resource assessment – estimation of the number and sizes of undiscovered fields, assessment of risk, and calculation of resource assessment curves – are not covered in this volume but are discussed in Allen and Allen (1990, Ch. 11). Oil and gas exploration companies and government agencies are likely to have their own methodologies and protocols that govern this task, and it is a specialized topic best researched through industry literature.

10.3 THE PETROLEUM CHARGE SYSTEM

10.3.1 Source rocks

Summary

There is now a wealth of geochemical evidence that petroleum is sourced from biologically derived organic matter buried in sedimentary rocks. Organic-rich rocks capable of expelling petroleum compounds are known as *source rocks*. In order to understand and predict the distribution and type of petroleum source rocks in space and time, it is necessary to consider the biological origin of petroleum. Source beds form when a very small proportion of the organic carbon circulating in the Earth's carbon cycle is buried in sedimentary environments where oxidation is inhibited.

In the world oceans, simple photosynthesizing algae (phytoplankton) are the main primary organic carbon producers. Their productivity is controlled primarily by sunlight and nutrient supply. The zones of highest productivity are in the surface waters (euphotic zone) of continental shelves (rather than open ocean) in equatorial and midlatitudes, and in areas of oceanic upwelling or large river input. The productivity of land plants is controlled primarily by climate, particularly rainfall. Coals have formed in the geological past, predominantly in the equatorial zone and in the cool wet temperate zone centred at about 55° latitude (N and S).

All living organic matter is made up of varying proportions of four main groups of chemical compounds – *carbohydrates*, *proteins*, *lipids*, and *lignin*. Only lipids and lignin are normally resistant enough to be successfully incorporated into sediment and buried. Lipids are present in both marine organisms and certain parts of land plants, and are chemically and volumetrically capable of sourcing the bulk of the world's oil. Lignin is found only in land plants and cannot source significant amounts of oil, but is an important source of gas. Geochemical studies of coal macerals have shown a very significant oil potential in the exinite group, comprising material derived from algae, pollen and spores, resins, and epidermal tissue.

The organic compounds provided to sea-bottom sediments by primitive aquatic organisms have probably not changed dramatically over geological time. In contrast, important evolutionary changes have taken place in land plant floras. As a result, a distinction can be made between the generally gas-prone Paleozoic coals, and the coals of the Jurassic, Cretaceous, and Tertiary, which may have an important oil-prone component.

Anoxic conditions (depleted in oxygen) are required for the preservation of organic matter in depositional environments, because they limit the activities of aerobic bacteria and scavenging and bioturbating organisms which otherwise result in the destruction of organic matter. Anoxic conditions develop where oxygen demand exceeds oxygen supply. Oxygen is consumed primarily by the degradation of dead organic matter; hence, oxygen demand is high in areas of high organic productivity. In aquatic environments, oxygen supply is controlled mainly by the circulation of oxygenated water, and is diminished where stagnant bottom waters exist. The transit time of organic matter in the water column from euphotic zone to seafloor, sediment grain size, and sedimentation rate also affect source bed deposition.

The three main *depositional settings* of source beds are lakes, deltas, and marine basins.

Lakes are the most important setting for source bed deposition in continental sequences. Favorable conditions may exist in deep lakes, where bottom waters are not disturbed by surface wind stress, and at low latitudes, where there is little seasonal overturn of the water column and a temperature–density stratification may develop. In arid climates, a salinity stratification may develop as a result of high surface evaporation losses. Source bed thickness and quality is improved in geologically long-lasting lakes with minimal clastic input. Organic matter on lake floors may be autochthonous, derived from freshwater algae and bacteria, which tends to be oil-prone and waxy, or allochthonous, derived from land plants swept in from the lake drainage area, which may be either gas-prone or oil-prone and waxy. The Eocene Green River Formation of the western USA, and the Paleogene Pematang Rift sequences of central Sumatra, Indonesia are examples of rich, lacustrine source rock sequences.

Deltas may be important settings for source bed deposition. Organic matter may be derived from freshwater algae and bacteria in swamps and lakes on the delta-top, from marine phytoplankton and bacteria in the delta-front and marine prodelta shales, and, probably most importantly, from terrigenous land plants growing on the delta plain. On post-Jurassic deltas in tropical latitudes, the land plant material may include a high proportion of oil-prone, waxy epidermal tissue. Mangrove material may be an important constituent. Examples of deltaic source rocks include the Upper Cretaceous to Eocene Latrobe Group coals of the Gippsland Basin, Australia.

Much of the world's oil has been sourced from *marine* source rocks. Source beds may develop in *enclosed basins* with restricted water circulation (reducing oxygen supply), or on open shelves and slopes as a result of *upwelling* or impingement of the *oceanic midwater oxygen-minimum layer.* Examples of modern enclosed marine basins include the Black Sea and Lake Maracaibo (Venezuela). Source bed deposition is favored by a positive water balance, where the main water movement is a strong outflow of relatively fresh surface water, leaving denser bottom-waters undisturbed. The Upper Jurassic Kimmeridge Clay Formation of the North Sea, and the Jurassic Kingak and Aptian–Albian HRZ Formations of the North Slope, Alaska, are examples of source rocks deposited in restricted basins on marine shelves.

The upwelling of nutrient-rich oceanic waters may give rise to exceptionally high organic productivity. Oxygen depletion may occur in the underlying bottom waters as oxygen supply is overwhelmed by the demand created by degradation of dead organic matter. Upwelling coastlines tend to be arid, and the organic matter in upwelling deposits is almost entirely of marine origin and strongly oil-prone. Upwelling may have played a part in the formation of source rocks such as the Permian Phosphoria Formation of the western USA, the Triassic Shublick Formation of the North Slope, the Cretaceous La Luna Formation of Venezuela and Colombia, and the Miocene Monterey Formation of California.

In open oceans whose floors are swept by cold, dense currents originating in the polar regions, an oxygen-deficient layer develops at depths of 100–1000 m. At times in the geological past, during periods of warmer climate and higher sea level, this layer may have intensified and impinged on large areas of the continental shelves and slope. The "global anoxic events" of the Mid-Cretaceous may have resulted from this process. The Toarcian source rocks of western Europe may also be an example.

The organic matter buried in sediments is in a form known as kerogen. *Geochemical measurements* may be used to determine the presence, richness, and stage of thermal maturity of a petroleum source rock, as well as the range of compounds likely to be generated and expelled. The richness or petroleum-generating potential of a source rock can be determined by measurements of Total Organic Carbon (TOC) and pyrolysis yield. Rocks with pyrolysis yields of greater than approximately 5 kg tonne^{-1} have the potential to be effective source rocks. More sophisticated geochemical techniques, such as gas chromatography and isotope studies, can be used to determine likely petroleum products, and in a range of other applications, including the correlation of source rocks with oils. Visual (optical) descriptions of kerogen may also give a useful guide to petroleum potential and petroleum type. From microscopic examination in reflected light, kerogen may be classified into the *exinite, vitrinite,* and *inertinite* groups. The exinite group comprises macerals with significant oil potential, whereas the vitrinite group is gas-prone. Inertinites have no petroleum-generating potential. Measurements of the reflectance of vitrinite are used as an index of thermal maturity (§9.7.2).

10.3.1.1 The biological origin of petroleum

Since the discovery by Treils in 1934 of a porphyrin "biological marker" compound in rock material, a wealth of geochemical evidence has accumulated to show that petroleum is sourced from biologically derived organic material buried in sediments. In order to understand the distribution in space and time of source rocks for oil and gas, it is necessary to first consider the characteristics of the biomass from which the organic material is originally derived. This section briefly discusses a number of topics: source bed deposition in the context of the overall carbon cycle; the main components of the biomass; geographical variations in organic productivity in the world's environments at the present day, and the main factors controlling these variations; changes in the composition of the biomass through geological time; the chemical composition of living organic matter and its likely hydrocarbon products.

THE CARBON CYCLE

The carbon cycle is initiated by photosynthesizing land plants and marine algae that convert carbon dioxide present in the atmosphere and seawater into carbon and oxygen using energy from sunlight (Fig. 10.6). Carbon dioxide is recycled back in many ways, the most important of which are back to the atmosphere by animal and plant respiration, by bacterial decay and natural oxidation of dead organic matter, and by combustion of fossil fuels – both natural and by humans. However, the importance of the carbon cycle to the petroleum geologist is that a small proportion of carbon escapes from the cycle as a result of deposition in environments where oxidation to carbon dioxide cannot occur. These environments are generally depleted in oxygen (for example, some restricted marine basins and deep lakes), or toxic for bacteria (swamps).

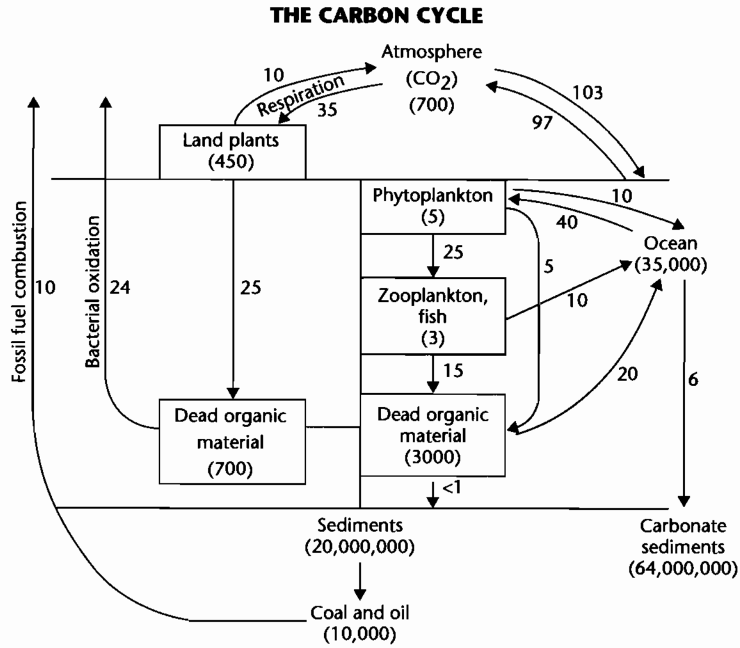


Fig. 10.6 The main elements of the carbon cycle. Numbers represent quantities in billions of metric tons (10^9 t). Numbers in parentheses represent stored quantities, numbers without parentheses are yearly fluxes. A relatively small amount of organic carbon escapes the carbon cycle to form organic-rich sediments, the source rocks for oil and gas. Data from Waples (1981).

The proportion of organic material buried in sediments in this way, relative to that originally produced, is very small (<1%), but over geological time is significant. Because it is preferentially concentrated in specific environments, it results in commercially significant petroleum source bed development. Petroleum is sourced therefore from organic carbon that has dropped out of the carbon cycle, at least temporarily. It rejoins the cycle when extracted by humans and combusted.

Organic production

The nature of organic production is quite different in continental and marine ecosystems. Continental ecosystems are dominated by land plants in low-lying coastal plain environments and by freshwater algae in lakes. Marine ecosystems are overwhelmingly dominated by phytoplankton.

Marine ecosystems

Figure 10.7 illustrates the fate of the 26.6×10^9 tonnes supply of organic carbon per year. Only a small percentage (0.4% according to Romankevich 1984) of the net carbon production in the world's seas and oceans is transferred to and preserved in sea bottom sediment.

Simple photosynthesizing algae are the primary organic carbon producers in the world's oceans, and are the start of a complex food chain. Phytoplankton are responsible for over 90% of the supply of organic matter in the world's oceans. The phytoplankton group includes the diatoms, dinoflagellates, blue green algae, and nannoplankton. Apart from phytoplankton, other organisms such as zooplankton, benthos, bacteria, and fish may also be important elements of the biomass. In the Black Sea (Romankevich 1984), annual bacteria production far exceeds even the phytoplankton. The main function of bacteria is to break down dead organic matter, but the

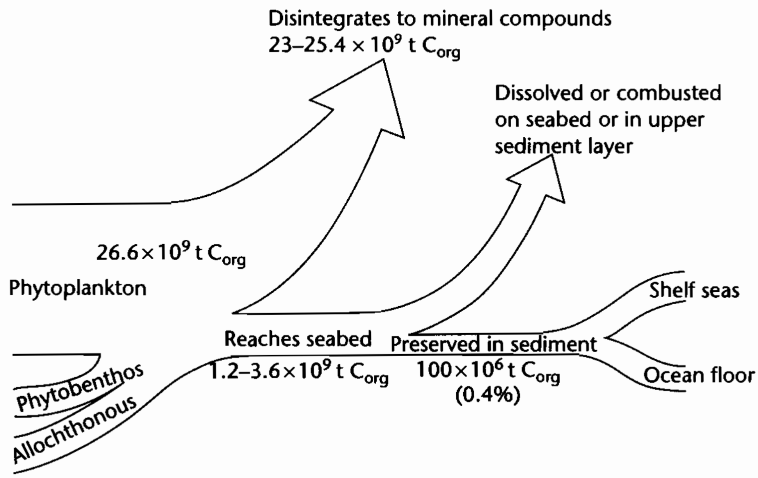


Fig. 10.7 Fate of the 26.6×10^9 tons of annual organic carbon (C_{org}) production in the world's oceans. In the order of 0.4% is preserved in the bottom sediments of shelf seas and ocean floors.

Table 10.1 Global net primary production (Woodwell et al. 1978; Nienhuis 1981).

Ecosystem type	**Area $10^6 km^2$**	**Total net primary production**		**Total plant mass of carbon $10^9 t C_{org}$**
		$10^9 t C_{org} yr^{-1}$	**$g C_{org} m^{-2} yr^{-1}$**	
Marine ecosystems including:	361.0	24.7	68.7	1.74
Algal bed and reef	0.6	0.7	1166.7	0.54
Estuaries	1.4	1.0	714.3	0.63
Upwelling zones	0.4	0.1	250.0	0.004
Continental shelf	26.6	4.3	161.6	0.12
Open ocean	332.0	18.7	56.3	0.45

bacteria may themselves also contribute to the organic content of the sediment.

Geographical variations in phytoplankton production in the world's marine environments are shown in Table 10.1 and Figure 10.8. Although the open ocean accounts for a large percentage of the organic carbon produced, the concentration of organic carbon per square meter in open ocean water is relatively low, which explains why the red pelagic oozes of the deep ocean basins are typically very lean in organic content. In contrast, the continental shelves are very rich, particularly in some specific environments of enhanced organic activity such as the algally dominated intertidal zone and in reefs and estuaries. Upwelling zones, such as those off the Peruvian coast at the present day, are also areas of relatively high organic productivity.

At a global scale, several trends in organic productivity may be recognized. Primary productivity decreases from coastal/marine shelf into open ocean. Mid-latitude humid and equatorial latitudes are more productive than tropical latitudes. Lowest productivity is in polar and tropical areas. The factors controlling organic productivity include:

- *Sunlight*: The zone of highest productivity is the top 200 m of the world seas, especially the upper 60–80 m. This is the *photic zone*;

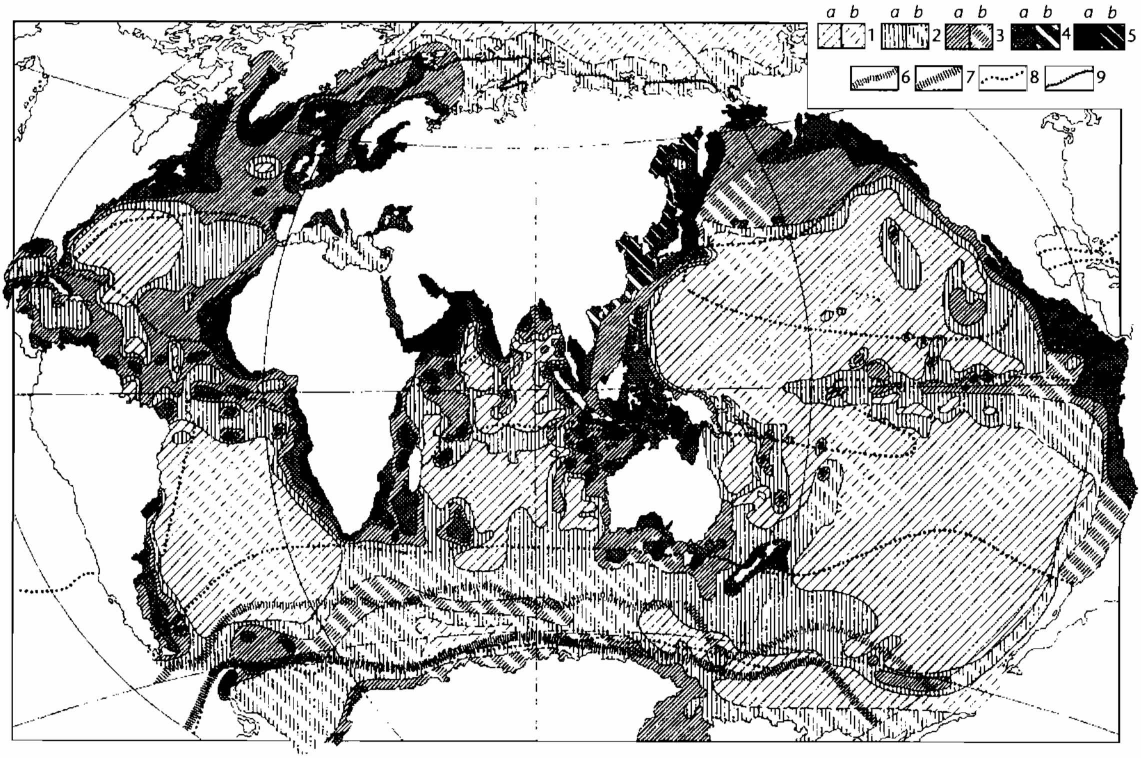


Fig. 10.8 Distribution of phytoplankton production in the ocean in units of mg C m^{-2} day^{-1}: 1=<100, 2=100–150, 3=150–250, 4=250–500; 5=>500. *a*, direct measurements; *b*, indirect data; 6, Antarctic convergence; 7, Antarctic divergence; 8, boundaries of climatic zones; 9, line with teeth, ice boundary in the Arctic. The highest phytoplankton productivities are in shelf areas rather than in oceans, particularly in algally-dominated intertidal zones, reefs, estuaries, and upwelling zones. (Reproduced with permission from Romankevich 1984.)

- *nutrient supply*: Nutrients, particularly nitrates and phosphates, are required to sustain high organic productivity. These are supplied by water circulation. Stagnant seas are not very productive. Ocean bottom currents set up by the sinking of very cold water in the polar regions may cause upwelling along the western coasts of continents in tropical latitudes. The best known examples are offshore Peru and west Africa. A rich nutrient supply is provided, and organic productivity is very high. Nutrient supply is also locally increased in areas of large river input and coastal abrasion;
- *turbidity*: Productivity is limited in areas with turbid coastal waters;
- *salinity*: Extremes of salinity (high or low) reduce the diversity of species present, though productivity of certain groups may still be very high;
- *temperature*: Temperature also influences the composition of the phytoplankton population, rather than net productivity. Dinoflagellates for example, require high water temperatures of >25 °C. Diatoms and radiolarians prefer 5–15 °C.

Figure 10.9 illustrates the concentration of organic carbon in sea-bottom sediment, and shows that a large proportion is in continental shelf environments. Organic productivity in surface waters is an important, but not sole factor controlling the concentration of organic matter in bottom sediments. Indeed, Demaison and Moore (1980) were unable to find a convincing systematic correlation between these two factors at the present day.

The critical factors for source bed development are the *deposition* and *preservation* of organic matter in significant

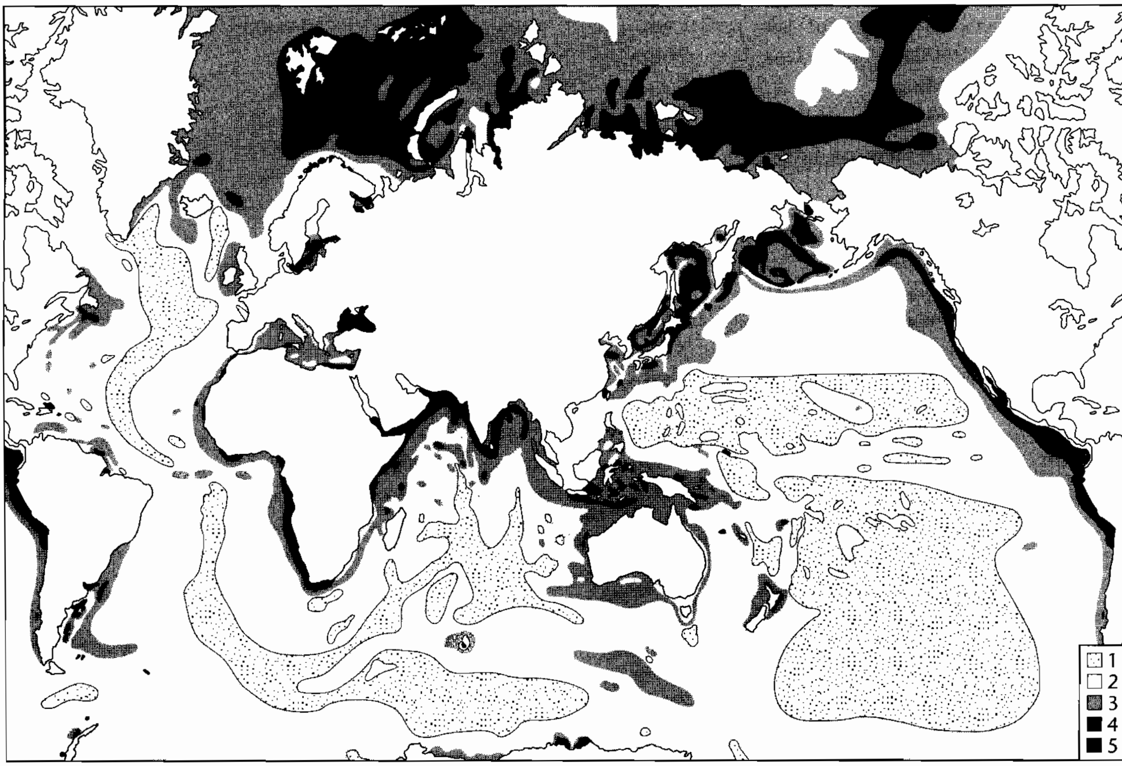


Fig. 10.9 Distribution pattern of organic carbon in the upper sedimentary layer (0–5 cm) beneath the world's oceans, in percentages on a dry weight basis. 1, <0.25; 2, 0.25–0.50; 3, 0.51–1.00; 4, 1.01–2.00; 5, >2.00. The highest organic carbon concentrations in bottom sediments are also in shelf areas. Organic productivity is a major controlling factor. (Reproduced with permission from Romankevich 1984.)

quantities in sediments, rather than organic productivity *per se*. Factors affecting the deposition and preservation of organic matter in sediment are discussed in §10.3.1.2.

Continental ecosystems

Organic productivity in continental ecosystems is dominated by land plants and freshwater algae.

The productivity of land plant material is controlled primarily by climate. Land plant material may be swept by rivers into lakes and adjoining marine areas, constituting an allochthonous organic supply. The most important allochthonous land plant deposit is peat, which forms below the water table in swamps or stagnant lakes where a wet climate allows luxuriant plant growth and topography causes poor drainage. A balance is necessary between the rate of accumulation of dead plant matter and the rate of subsidence. Accumulated peat may be preserved where bacterial decay of the dead organic matter is inhibited by anoxic or toxic conditions and where net subsidence takes place. Peat swamps form in the lower delta plain environment, typically in the lagoonal areas behind coastal spits and barriers, and in bays between vertically accreting distributary channels.

Ancient coal occurrences can be predicted using paleoclimatic maps such as those of Parrish et al. (1982). Paleolatitude studies show that coals ranging in age from Early Triassic to mid-Miocene are concentrated in the equatorial zone and in the cool wet temperate zone centred on about 55° N and S.

Freshwater algae make an important contribution to the organic matter supply in lakes. An example is the present day alga, *Botryococcus*. Ancestors of *Botryococcus* have been identified in ancient lake sediments, and derived geochemical compounds have been recognized in many lake-sourced oils.

CHEMICAL COMPOSITION OF LIVING ORGANIC MATTER

The chemical compounds that make up all living organic matter fall into four groups. These are: (i) carbohydrates, (ii) proteins, (iii) lipids, and (iv) lignin.

Carbohydrates are compounds that function as sources of energy and as supporting tissue in plants and some animals. Examples are sugar, such as glucose and fructose, starch, cellulose, and chitin. Cellulose is an important supporting tissue in land plants, while chitin is the material manufactured by crustaceans to form a hard protective exoskeleton.

Proteins are organic compounds made up of amino acids, and perform a variety of biochemical functions vital to life processes. Examples are enzymes, hemoglobins, and antibodies. Proteins also make up most of the organic matter in shells and substances such as hair and nails.

Lipids are a range of organic substances that are insoluble in water, and include animal fats, vegetable oils, and waxes. They are similar in chemical composition to petroleum. Lipids are abundant in marine plankton, and are present in the seeds, fruit, spores, leaf coatings, and barks of land plants. A range of lipid-like substances, for example sterols, are important biological markers in crude oils.

Lignin and *tannins* are compounds common in higher plants. Lignin is the substance that gives strength to plant tissue, for example in trees, providing a much firmer support than cellulose. Tannins are found in some tree barks, seed coats, nut shells, algae, and fungi.

Other important organic compounds are *resins* and *essential oils*. Resins are found in the wood and leaf coatings of trees, and are particularly resistant to chemical and biological attack.

The relative amounts of these groups of organic compounds in living organisms varies enormously (Table 10.2). Factors such as food supply and overcrowding are also known to affect lipid content. Of the four groups of compounds, proteins and carbohydrates are very susceptible to degradation, and tend to be dissolved, oxidized, or bacterially degraded, without being incorporated in sediment beyond its surface layers. In contrast, lipids and lignin are much more resistant to mechanical, chemical, and biochemical breakdown, and under the conditions to be discussed later, will be buried successfully in sediment. Lipids are closest in chemical composition to petroleum. A relatively small number of chemical changes are involved in transforming lipids into petroleum, and more petroleum can be produced from lipids than from any of the other substances. The lipid content

Table 10.2 Composition of living matter (Hunt 1980).

	% Weight (ash-free basis)			
	Proteins	**Carbohydrates**	**Lignin**	**Lipids**
Plants				
Land plants				
Spruce wood	1	66	29	4
Oak leaves	5	44	32	4
Scots-pine needles	7	41	15	24
Diatoms	29	63	0	8
Lycopodium spores	8	42	0	50
Animals				
Zooplankton	53	5	0	15
Copepods	65	22	0	8
Higher invertebrates	70	20	0	10

of organic matter buried in sediments is probably sufficient to source all of the world's known oil.

If the biological precursors of petroleum can be microscopically identified, we can go a long way towards predicting the kind of hydrocarbons that are likely to be generated. Marine organic matter in sediments tends to be amorphous, but much of our understanding of the generating potential of land plant source rocks is derived from coal petrography. A large number of coal macerals have been identified. The three main groups are listed below. Kelley et al. (1985) have geochemically analyzed the generating potential of some macerals:

- *Vitrinite* is derived from the lignin and cellulose component of plant tissues. It is normally the largest constituent of the so-called *humic coals*, and generates predominantly gas;
- *inertinite* is also derived from the lignin and cellulose of plants, but has been oxidized, charred, or biologically attacked. The consensus is that it has negligible hydrocarbon generating potential. What potential it has is for gas. Dispersed inertinite has, however, been proposed as one of the sources of the liquid hydrocarbons in the Permian Gidgealpa Group of the Australian Cooper Basin;
- *exinite* is a diverse group of macerals: (i) *Alginite* is derived from algae, and when abundant forms a *boghead* or *cannel coal*. It is the main constituent of the torbanites of Scotland. This type of coal is quite rare, being most common in the Permo-Carboniferous. The algae responsible for these alginites are similar to the modern freshwater alga *Botryococcus*. Alginite is strongly oil prone. (ii) *Sporinite* is derived from the spores and pollen of plants, and may be abundant in coals from the Devonian through to the present day. The sporinite in Paleozoic coals is derived mainly from spores, whereas in Mesozoic and Tertiary sporinite, pollen predominates. Spores and pollen are extremely lipid-rich (50%) and may give rise to excellent oil-prone source rocks. Since spores and pollen are often transported large distances by wind or water, oxidation before burial in sediment often occurs. The best source rocks are therefore those in which the spores and pollen are autochthonous to the depositional environment, as for example in a coal swamp. (iii) *Resinite* is derived from the resins and essential oils of land plants. It is a prolific source of napthenic and aromatic hydrocarbons. (iv) *Cutinite* is derived from the protective surface coating or cuticle of higher plants. The cuticle occurs on the outside of the epidermal tissue. It is rich in hydrocarbon waxes, and is thus an important oil source. Poor preservation may result in a gas-prone cutinite, with very little remaining oil potential.

Thus, all of the exinite macerals have oil generating potential. Preservation of the maceral is, however, critical. This is a function of the transport route and distance, and the depositional environment The oil generating potential of sporinite and cutinite is particularly strongly affected by poor conditions for preservation.

Of the four groups of compounds found in living organic matter therefore, only lipids and lignins are likely to be substantially incorporated into sediment beyond the surface layer. Lipids are present in both marine organisms and parts of land plants, are chemically suited to sourcing petroleum, and could account for all of the world's known oil. Lignin is found only in land plants. It is unlikely to source oil, but is an important source of gas.

CHANGES IN THE COMPOSITION OF THE BIOMASS THROUGH GEOLOGICAL TIME

The ancestors of the primitive aquatic organisms that comprise phytoplankton, zooplankton, and bacteria may be traced back into the Precambrian with little apparent evolutionary change. The kind of aquatic organic matter buried in marine sediment has therefore probably changed very little over geological time. For land plants, however, important floral changes have taken place since their appearance in the Late Silurian–Devonian that have had a major impact on the hydrocarbon generating characteristics of the source rocks in which they are buried (Fig. 10.10).

The Carboniferous coals of the northern hemisphere and the Permian coals of the southern hemisphere contain floras dominated by early plant groups (mostly lycopods) without extensive foliage. The resulting coal macerals are gas-prone vitrinite and its oxidation product inertinite, with minor amounts or local concentrations of sporinite, resinite, cutinite, and alginite. Paleozoic coals, therefore, tend on the whole to be gas-prone.

Important evolutionary changes took place in floras in the Jurassic and Cretaceous. Conifers became dominant in the Jurassic, and angiosperms (flowering plants) appeared in the Cretaceous. Both these plant groups are rich in waxy epidermal tissue and resin, and have significant oil generating potential. Large volumes of gas are also generated from coals of this type, since vitrinite is normally still abundant. Most of Australia's waxy oils have been sourced from coals of this type, most notably the Gippsland Basin oils from the Early Tertiary Latrobe

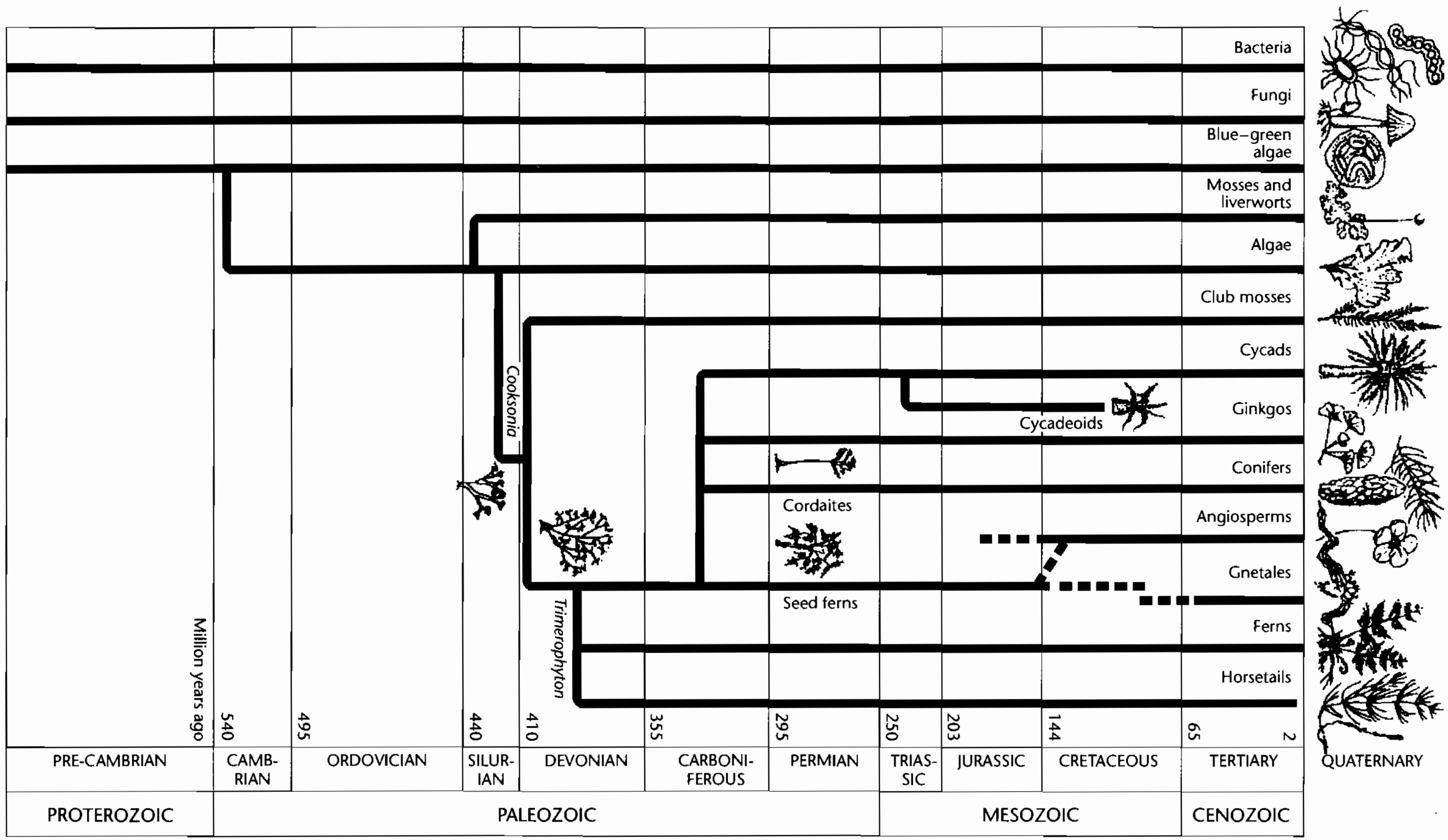


Fig. 10.10. Plant evolution over the last 600 Myr. The first land plants (primitive vascular varieties) such as Cooksonia appeared in the Silurian. A large number of new groups evolved in the Devonian. Important changes in land plant floras have taken place since the Silurian which have affected their hydrocarbon-generating characteristics. Only Mesozoic and Tertiary land plants have significant oil-generating potential. Today, two main groups dominate the land; the *conifers*, which cover over more than $10 \times 10^6 km^2$ of the Earth's surface, mainly in the cooler, drier areas, and *flowering plants* (angiosperms), which occur everywhere. The conifers may date back as far as the Carboniferous. The oldest definite flowering plants in the geological record are Barremian (Early Cretaceous), but some authors place their origin in the Late Jurassic. In the sea, organisms adapted to life in water, such as the algae, have undergone their own evolution.

Group, and the Eromanga and Surat Basin oils from the Jurassic (Thomas 1982).

Thus, evolutionary changes in land plant floras through geological time are responsible for the oil-prone component of Mesozoic and Tertiary coals, while Paleozoic sediments are more typically sources solely for gas.

10.3.1.2 Source rock prediction

Introduction: Anoxia

Anoxic conditions are critical to the preservation of organic matter in sediments. Source rock prediction is therefore concerned primarily with predicting where and when in the geological past anoxic conditions are likely to have existed. Questions addressed in this section are: "What causes anoxic conditions?" and "In what geological environments are anoxic conditions likely to develop?"

"Anoxic" means "devoid of oxygen," but the term is frequently used in the sense of "depleted in oxygen" – *dysaerobic*. "Anaerobic" means that insufficient oxygen is available for aerobic biological processes. This critical oxygen concentration is different for different organisms. Below 1.0 milliliters of oxygen per liter of water there is a serious reduction in biomass, but deposit-feeding organisms (those responsible for bioturbation of the sediment) can persist down to concentrations of $0.3\,ml\,l^{-1}$. As a general guide, $0.5\,ml\,l^{-1}$ may be taken as the oxic/anoxic threshold. Anoxic conditions are critical for source bed deposition because they prevent the scavenging of dead organic matter and bioturbation of the surface sediment by benthic fauna and degradation of organic matter by bacteria, which would otherwise destroy the organic matter prior to burial. Anoxic conditions develop where *oxygen demand* exceeds *oxygen supply*.

Oxygen demand is caused primarily by the degradation of dead organic matter. Large amounts of organic matter are supplied to the seafloor in areas of high surface organic productivity (photosynthesizing algae in the euphotic zones of seas and lakes) and/or where there is a large terrigenous supply of organic matter. Oxygen is consumed as the dead organic matter is degraded.

Oxygen supply is controlled by the circulation of oxygenated water. This may be a downward movement of oxygen-saturated surface waters as a result of mixing by waves, or a movement of cold, oxygen-bearing ocean bottom currents. Cold water can dissolve more oxygen than warm water. A feature of the world's oceans at the present day is that cold, dense water carrying large amounts of oxygen descends in the polar regions and moves over the ocean floor towards the equator, bringing oxygenated conditions to almost all parts of the oceans. It is reasonable to expect, however, that there were times in the past when such a circulation was less well developed. This has important implications for source bed deposition.

A sea or lake floor, therefore, is prone to anoxic conditions primarily under the following two sets of circumstances: (i) when organic productivity in the overlying water column is very high and the system becomes overloaded with organic matter, and (ii) when stagnant bottom water conditions exist, causing a restriction in the supply of oxygen. These factors largely determine the geological settings in which source beds are deposited.

Source beds may, under exceptional circumstances, be deposited under oxic conditions. This sometimes occurs when sedimentation rate is very high. A special case is when mass gravity flows deposit an anoxic sediment almost instantaneously into oxic waters. As a rule, however, a source rock is not expected to be developed under oxic conditions.

The factors that affect the development of anoxia are discussed in more detail in the next section.

Factors affecting source bed deposition

An understanding of anoxic environments and their importance in petroleum exploration has rapidly developed since the 1980s (e.g., Demaison and Moore 1980). We have seen that anoxic conditions are a prerequisite for source bed deposition primarily because they prevent the bacterial degradation of dead organic matter and the scavenging and bioturbation of the surface sediment by benthic fauna. These and other factors will now be discussed in greater detail.

Bacterial degradation

Degradation of organic matter by bacteria takes place in both the water column and in sediment pore waters, under both aerobic and anaerobic conditions (Fig. 10.11). Organic matter is oxidized by aerobic bacteria using the available oxygen in the environment until there is no more organic matter to oxidize or there is no more oxygen. If the latter, the environment becomes anoxic. Anaerobic bacteria derive oxygen first of all from nitrates, and then from sulfates. It is thought that they

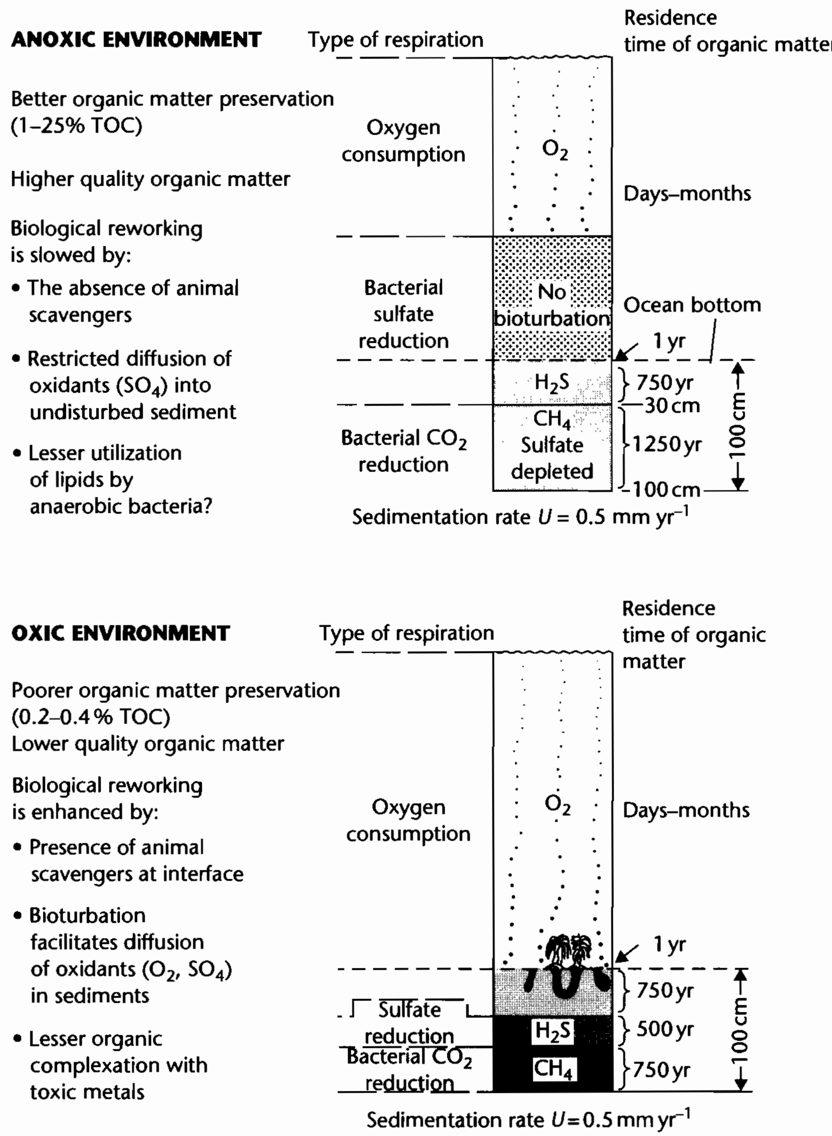


Fig. 10.11 Degradation of organic matter under anoxic and oxic conditions (after Demaison and Moore 1980). Anoxic environments are the primary sites of organic matter preservation because scavenging and bioturbation by benthic fauna and aerobic bacterial degradation are inhibited.

can degrade organic matter just as fast as aerobic bacteria. An important difference, however, is that anaerobic degradation appears to result in a greater preservation of lipid-rich, oil-prone material. Furthermore, under anoxic conditions, the bacteria population itself may contribute significantly to the preserved organic matter.

Scavenging and reworking by benthic fauna

The role of benthic metazoans such as worms, bivalves, and holothurians is critical to the preservation of organic matter. Their activity is important in two respects. First, they consume particulate organic matter in the water just above the sea or lake floor and in the surface sediment itself. Second, burrowing metazoans churn up the sediment to a depth of 5–30 cm, allowing the penetration of oxygen and sulfates into the sediment column, thus promoting bacterial degradation.

Bioturbation seems to take place at all water depths under oxic water columns. Below oxygen concentrations of 0.3 $ml\,l^{-1}$ this activity is virtually eliminated, and sediments remain laminated and organic-rich. Even the activity of anaerobic sulfate-reducing bacteria is limited because oxidants cannot easily penetrate the surface. The occurrence of unbioturbated laminated muds in the Gulf of California is closely correlated with low oxygen concentrations in bottom waters (Fig. 10.12). For these reasons, organic matter stands a much better chance of being preserved in the absence of benthic fauna, that is, in anoxic environments.

Transit time of organic matter in the water column

Almost all marine organic matter is formed by photosynthesis in the euphotic zone. Before it can accumulate on the seabed it has to fall through a water column of up to 6 km (in deep ocean areas). The smallest particles take the longest to fall, faecal pellets falling the fastest. Organic matter is scavenged by fauna during its transit through the water column. Preservation of organic matter is therefore favored by shallow water depths and large organic particle size. Scavenging in the water column is probably one of the factors that contributes to the general lack of source bed deposition in deep ocean areas. Another factor is low organic productivity due to remoteness from nutrient supply.

Sediment grain size

The low permeability of fine-grained sediments inhibits the diffusion of oxidants from the water column into the sediment, and, as a result, bacterial activity is lower than in coarse-grained sediment. Coarse-grained sediment is usually associated with high energy environments that are in any case likely to be well oxygenated.

Sedimentation rate

Under oxic conditions, high sedimentation rates favor source bed deposition because they reduce the period during which organic matter is subject to metazoan grazing, bioturbation, and aerobic bacterial attack. Sufficient organic matter may be preserved even under oxic

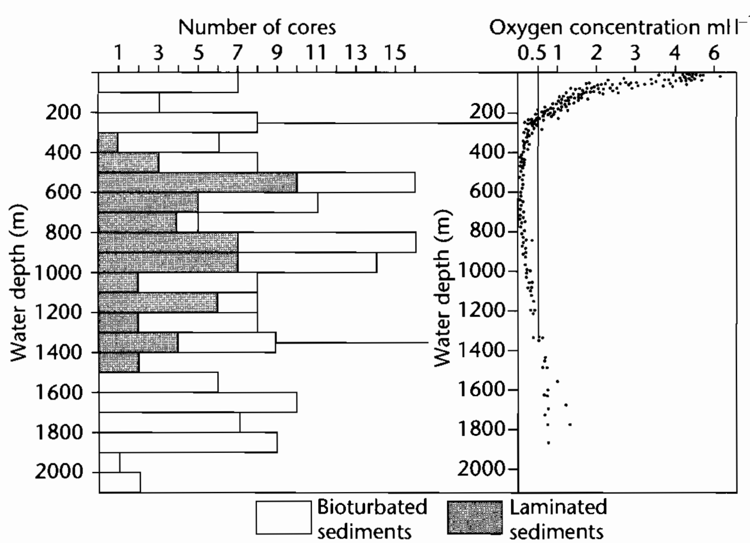


Fig. 10.12 The correlation of laminated sediments with low oxygen concentrations in the bottom waters of the Gulf of California demonstrates that bioturbation is limited by oxygen concentrations of less than 0.5 $ml\,l^{-1}$.

conditions to form a source bed. The organic matter becomes diluted, however, by the large amount of mineral matter in the sediment and the resulting source rock usually has a low organic matter concentration. It may not be capable of generating sufficient liquid hydrocarbons to saturate the source rock and expel oil. Hydrocarbons may instead be expelled at high maturity as gas. Rapidly deposited successions such as thick, muddy prodeltas, therefore, rarely contain good oil sources. Under anoxic conditions, high sedimentation rates are likely to have only an adverse diluting effect on organic content. Deposition of rich source beds is therefore favored by low sedimentation rates.

The ideal conditions for oil source bed deposition are therefore: (i) anoxic conditions with high organic productivity and restricted oxygen supply (poor water circulation), (ii) shallow water depths, and (iii) fine-grained sediment. Under oxic conditions, moderate sedimentation rates favor source bed deposition.

Depositional settings of source beds

The main depositional settings of source beds are lakes, deltas, and marine basins. There are a number of other less important settings, including freshwater swamps, nondeltaic shorelines, and continental slopes and rises, which appear to have sourced a relatively small proportion of the world's oil and, in terms of source prediction, provide only a relatively low probability of source bed presence.

Lakes

Lakes are the most important depositional setting for source beds in continental stratigraphy (§8.5.2). In order to form volumetrically significant source beds, lakes must be geologically long-lasting. Anoxic conditions develop in "permanent" lakes when the water column becomes stratified. This is most likely to occur in the following circumstances (Allen and Collinson 1986 for summary):

- *In deep lakes*: Whereas wind stress causes the mixing of the whole water column in shallow lakes, causing oxygenation of bottom waters and sediments, deep lakes commonly have anoxic hypolimnia. The 1500 m-deep Lake Tanganyika in the East African rift system is anoxic below 150 m. TOCs (total organic carbon) of 7–11% have been recorded from bottom sediment in the anoxic part of the lake. In contrast, the shallower Lake Mobutu (Albert) and Lake Victoria are oxic;
- *at low latitudes*: Wide seasonal variations in weather cause overturn of the water column, and cold, dense river waters carrying large amounts of dissolved oxygen sink to the bottom of temperate lakes, causing oxygenation. Consequently, all temperate lakes at the present day, even the 1620 m-deep Lake Baikal, are oxygenated for at least part of the year. In warm, tropical, equable climates river water is less dense, does not have a tendency to form high-density underflows, and carries less oxygen. These conditions favor the development of anoxic conditions. In addition, the temperature–density behavior of water (Ragotzkie 1978) means that more work is required to mix two layered water masses at elevated temperatures (e.g., 29 °C and 30 °C) than at low temperatures (e.g., 4 °C and 5 °C), so tropical lakes tend to stratify easily. On the other hand, the slightest cooling in a tropical lake may initiate convection currents which may eventually affect the entire water body, causing mixing and oxygenation of bottom waters;
- *abundant water supply*: a wet climate ensures that the lake is kept filled with water, whereas in arid climates lakes may intermittently dry up, resulting in oxidation of its surface sediment. Provided this does not happen, however, high evaporation losses may encourage anoxia, by producing a *salinity stratification*. Salinity stratified lakes may form important source environments in low latitudes. Ancient examples are the Devonian Orcadian basin of the UK (review in Allen and Collinson 1986) and the Eocene Green River Formation of western USA (Eugster and Hardie 1975).

Hydrothermal solutions in areas of volcanic activity, and run-off over peralkaline volcanic products, may produce alkaline lakes. Strongly reducing conditions may develop at the lake floor. Distinctive mineral assemblages are characteristic of alkaline lakes. The Lakes Magadi and Natron of East Africa are today precipitating trona, and the Wilkins Peak Member of the Eocene Green River Formation of Colorado and Utah has a similar evaporite mineralogy.

Source beds will be richer and thicker and more likely to develop if a deep lake can be maintained for a long time with the minimum of particulate input. Clastic input is a complex function of topographic, climatic, and bedrock variables in the catchment area of the lake (see Chapter 7). Hilly or mountainous relief in tectonically active regions commonly causes rapid erosion and the rapid infilling of a lake basin by coarse detritus. Small lakes are prone to be swamped with clastic input, whereas the centres of large lakes may see little terrigenous influence. If the hinterland is an area of carbonate outcrop, however, much of the weathering is chemical rather than mechanical, and the suspended particulate input to the lake is small. Chemical weathering is dominant in humid climates, rocks quickly breaking down under the combination of high temperatures and abundant water. Lush vegetation, particularly grasses, in the drainage area will tend to reduce the amount of surface erosion, and hence the particulate input to the lake.

Organic matter input to lakes is of two types:

- *Produced within the lake itself (autochthonous)*, comprising algae and bacteria. It produces strongly oil-prone kerogen. Ancestors of the present day alga *Botryococcus braunii* have been identified in ancient lake sediments, and its biomarker compound Botryococcane has been recognized in many lake-sourced oils. An example is the oil of the Minas field in central Sumatra (Williams et al. 1985);
- *swept into the lake from the drainage area (allochthonous)*, comprising organic matter from higher plants. Much of the allochthonous supply is lignin, which is gas-prone, but there may also be a contribution of oil-prone waxy epidermal tissues, spores or pollen. As discussed previously, these oil-prone components are only likely to be important in tropical areas since the Jurassic. Terrigenous organic matter is likely to dominate a small lake. In large lakes, it may be concentrated around the margins (particularly around river mouths) leaving the centre the site of algal and bacterial organic matter deposition.

Lake sediments may source oil, gas-condensate, or gas, depending on the factors discussed above. Lacustrine oils tend to be very variable in density, low in sulfur, and have a very variable wax content, ranging up to 40%. Wax is derived from land plant cuticles and from wax-secreting freshwater algae.

The lacustrine oil shales of the *Eocene Green River Formation* of Utah, Wyoming, and Colorado accumulated in paleolakes Uinta and Gosiute, now preserved in the Uinta and Piceance Creek sub-basins (Lake Uinta) and the Green River and Washakie sub-basins (Lake Gosiute) (Smoot 1983; Dubiel 2003). A range of lacustrine environments are represented by the members of the Green River Formation. Some of the most important oil source rock units (e.g., Laney Shale, Mahogany Oil Shale) were deposited in deep, anoxic, density-stratified, generally saline lakes, while *hypersaline* shallow lakes (Wilkins Peak and Parachute Creek members) and their fringes were also sites of significant organic matter accumulation. Hypersalinity and lack of sulfate inhibited bacterial oxidation of the organic matter. Arid conditions precluded significant land plant input to the lake systems; organic matter is, as a result, autochthonous and oil-prone.

In contrast to the saline and hypersaline units of the Green River Formation, the Pematang lake sediments of the *Paleogene Rifted Basins of Central Sumatra, Indonesia*, are deposits of low salinity lakes (Williams et al. 1985). The Pematang reaches up to 1800 m in thickness and was deposited in structurally controlled half-grabens, under humid tropical conditions. The most important oil source rock unit is the Brown Shale Formation, which represents the deposits of deep lakes formed by rapid synrift subsidence. These are well-laminated, reddish brown to black noncalcareous mudstones. Geochemical correlations demonstrate a convincing match between Brown Shale algal source rocks and crude oils, including those of the giant Minas and Duri fields. In contrast to the deep-lake oil-prone Brown Shale Formation, gas condensate-prone land plant source rocks predominate in the shallow lake sequences of the Coal Zone Formation.

Albian–Turonian lacustrine source rocks have been described from the *Songliao Basin of eastern China*. These represent the deposits of deep thermally stratified freshwater lakes. Small-scale examples of rich oil-prone lacustrine source rocks have been described from the Tertiary Mae Sot and Mae Tip Basins of northwest Thailand (Gibling 1985a, b). They were deposited in shallow fresh to brackish lakes.

Deltas

Deltas may be an important setting for source rock deposition (§8.5.3). In SE Asia and Australasia, deltas appear to have sourced a large proportion of the discovered oil. Constructive deltas (fluvial or tide dominated) are characterized by persistent low-energy environments on the delta top which favor source bed deposition. Destructive or static deltas (wave dominated) generally provide less favorable environments for source bed deposition. Migration of shoreline bars tends to rework the sediments in the lower delta plain, and organic matter is usually degraded to an inert state.

Organic matter in deltaic stratigraphy may be of three types:

- *Freshwater algae (phytoplankton) and bacteria* present in lakes, swamps, and abandoned channels on the delta top. This material is oil-prone. It will only be preserved if anoxic conditions exist at the sediment surface. Fluvial channel migration results in the infilling of lakes in deltaic environments. Lakes are most likely to persist, therefore, in the upper part of the delta plain. High subsidence rates on the lower delta plain may allow lakes to persist despite rapid sedimentation rates, as occurs on the Niger and Nile deltas at the present day;

- *marine phytoplankton and bacteria* in the delta front and prodelta areas. Abundant nutrients provided by river input frequently stimulate high organic productivity in the marine basin into which the delta debouches, but conditions for preservation are generally poor. Preservation requires anoxicity in the marine basin. The delta front is normally a high-energy, oxic environment. High accumulation rates allow the preservation of some organic matter, but it is strongly diluted with mineral matter, and source rocks are usually lean with potential to expel only gas;
- *terrigenous land plant material.* Vegetation growing on the delta plain contributes a large amount of organic matter to depositional environments. On tropical deltas since the Jurassic, the land plant material is likely to comprise both oil-prone (waxy epidermal tissues, resins, spores) and gas-prone (lignin) material. Pre-Jurassic and temperate land plants are predominantly gas-prone. The most prolific sites of accumulation are the interdistributary peat swamps, where *in situ* coals may form. Terrigenous organic matter may, however, be dispersed across the entire delta top, and into the prodelta environment where preservation will largely depend on high sedimentation rate. In peat swamps, the high accumulation rates, highly acidic conditions, and presence of bactericidal phenol compounds released from lignin, enhance the preservation of organic material. In the upper part of the delta plain, freshwater swamps dominate. On the lower delta plain, where waters are brackish to saline as a result of some marine influence, mangrove swamps dominate. Mangroves trap plant material drifted in from the freshwater upper delta plain. Terrigenous organic matter may also be reworked onto low energy tidal flats.

Mangrove-dominated shorelines may be important source depositional environments. A modern example is Missionary Bay, north Queensland, Australia (Risk and Rhodes 1985). Mangrove litter originating on intertidal mudflats is swept into the adjoining anoxic bay bottom sediments, providing organic matter with a very high lipid content. The mangrove swamps are sites of prolific organic productivity. A thin intertidal strip of mangrove swamp may produce a vast quantity of lipid-rich organic matter and spread it over a large offshore area. The high oxygen demand caused by the abundant influx of mangrove detritus may cause anoxia in the surrounding depositional environments. Mangrove material is also relatively resistant to degradation, both physical and chemical. Under fungal and bacterial attack, the waxy lipid-rich cuticle that coats mangrove epidermal tissue appears to be preferentially preserved. Mangrove material is likely to source oils that have a high wax content.

Reworking of upper delta plain plant material in brackish conditions appears to result in a selective bacterial (or fungal) degradation of cellulose and lignin (to humic acids), leaving a relative enrichment in oil-prone waxy and resin components (Thomas 1982).

The Upper Cretaceous–Eocene *Latrobe Group* of the Gippsland Basin of SE Australia (Shanmugam 1985) have sourced about 3000 million barrels of oil. The coals are dominantly vitrinitic but contain up to 15% exinite macerals, comprising cutinite, sporinite, and resin. These components are derived from the cones, bark, seeds, leaves, and resin bodies originating in the adjacent coniferous forests. The climate was temperate and wet. Oils have been geochemically matched with these coals, and have typical coal source characteristics, including high wax content (<27%).

Marine basins

Marine source rocks may form in enclosed, silled basins such as the Black Sea, Baltic Sea, and Lake Maracaibo, or on open marine shelves and continental slopes. The mechanisms for source bed development in each of these settings are quite different. Enclosed basins are typified by water stratification, which reduces oxygen supply. Open shelves and slopes are characterized by oceanic upwelling causing high organic productivity and hence high oxygen demand. Impingement of the oceanic midwater oxygen minimum layer may also reduce oxygen supply.

(a) Enclosed basins

These marine basins are physically restricted to some extent, by land or by chains of islands, but retain some connection with the open sea. Water exchange is limited, however, and the basin is prone to water stratification and hence anoxic conditions. The nature of the water exchange with the open sea is important, since not all enclosed basins become anoxic.

A *positive water balance* is where the outflow of freshwater (as a surface layer) exceeds the relatively small inflow of deeper saline water. Most of the water movement takes place in the surface layers, allowing stratification of

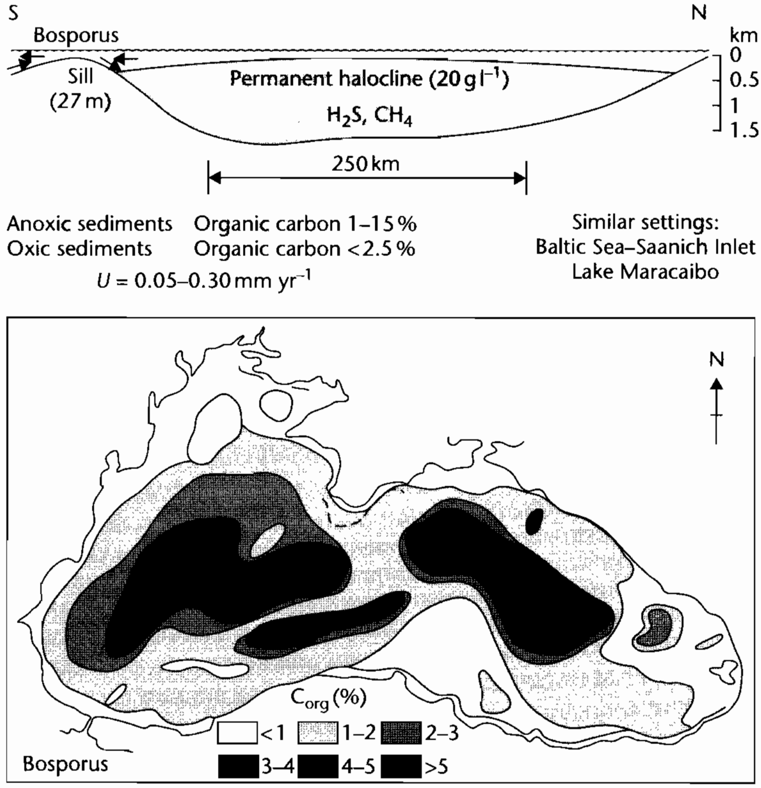


Fig. 10.13 Geometry and total organic carbon concentrations in modern sediments of the Black Sea. This is an example of a silled marine basin with a positive water balance. Organic carbon concentrations are locally up to 15% in the deeper parts of the basin (after Demaison and Moore 1980).

deeper waters. This process occurs in the Black Sea, Baltic Sea, and Lake Maracaibo. The Black Sea is one of the best-documented anoxic silled marine basins (Fig. 10.13). Total organic carbon is <15% in sediment 7000–3000 years old. At the present day, it is anoxic below 150–250 m water depths. In contrast, a *negative water balance* is where the inflow of oceanic water dominates over a relatively meager freshwater input. This often develops in arid climates where high evaporation losses at the surface cause the sinking of oxygenated waters (Fig. 10.14). Examples of oxic enclosed basins include the Red Sea, Mediterranean Sea, and Persian Gulf. The Mediterranean is the world's largest silled marine basin, but it is well oxygenated and organic contents in bottom sediment are very low.

Size and depth of enclosed basins do not appear to be critical. Lake Maracaibo, for example, is only 30 m deep.

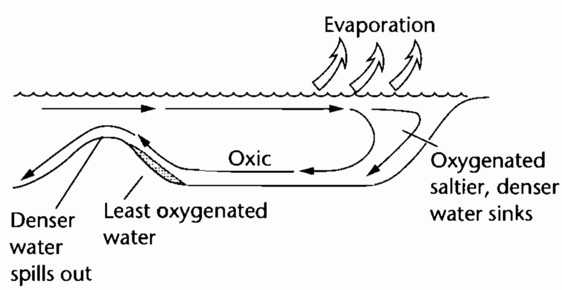


Fig. 10.14 Model for a silled marine basin with a negative water balance (after Demaison and Moore 1980). Oceanic inflow dominates over freshwater fluvial input, a situation that commonly develops in arid climates. Dense, salty, oxygenated waters resulting from surface evaporation may sink and sweep the basin floor, preventing anoxia.

The danger of water mixing by wind-generated waves, however, renders shallow basins less favorable source bed environments. Enclosed basins may range in size up to the South Atlantic Ocean during the Aptian. Small basins tend to be short-lived, particularly when there is high clastic input.

Organic matter type in enclosed marine basins depends on the amount of terrigenous land plant material brought into the basin by rivers. Wet climates imply a positive water balance and hence a tendency to water stratification. However, high terrigenous organic input may produce gas-prone source rocks. In arid climates, the organic matter is made up largely of marine phytoplankton and, when source beds are developed (often in association with carbonates and evaporites), they are predominantly oil-prone. The Devonian of the western Canada basin is believed to be an example. Source bed deposition is sensitive to changes in the water balance of the basin, and tends to be periodic and of varying lateral extent. Deep, big, enclosed marine basins in areas of wet paleoclimate offer the highest probability of source bed occurrence.

Examples of source rocks deposited in restricted marine basins probably include the Upper Jurassic Kimmeridge Clay Formation of the North Sea, and the Jurassic Kingak and Aptian–Albian HRZ Formation of the North Slope, Alaska.

(b) Open marine shelves

Upwelling occurs along coastlines where wind-driven currents flowing parallel to the coast are deflected offshore by the Earth's rotational (Coriolis) force. It is most common on the east side of oceans. Upwelling occurs today along the coasts of Peru–Chile, California, Namibia, and Morocco. The deep ocean water drawn into the upwelling cell to replace the offshore moving surface water is rich in nutrients such as phosphates and nitrates, and can give rise to exceptionally high organic productivity in the near-surface photic zone. Degradation of dead organic matter creates a high demand for oxygen, and anoxicity may develop in the underlying waters. Underneath the Benguela current offshore Namibia, for example, there is a 340 km by 50 km oxygen depleted zone. Under this zone, the sediment contains 5–26% total organic carbon (Fig. 10.15) (Demaison and Moore 1980). The organic matter is almost entirely made up of marine plankton. There is very little terrestrial input from the arid hinterland, a feature of many upwelling coastlines at the present-day.

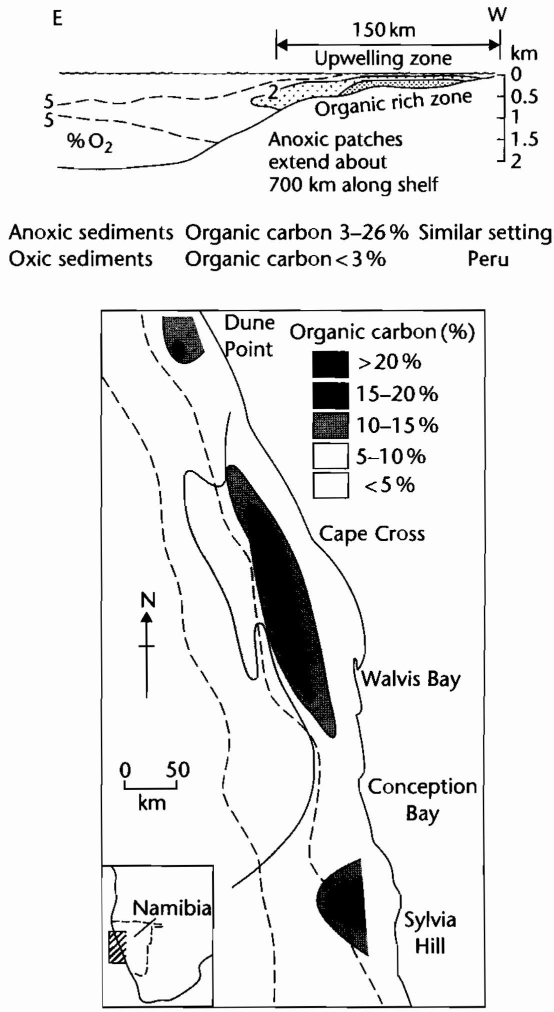


Fig. 10.15 Upwelling zone, offshore Namibia, showing oxygen-depleted zone, and total organic carbon concentrations of up to 26% (after Demaison and Moore 1980). Upwelling causes high phytoplankton productivity in surface waters. The sea bottom sediments are anoxic under the highly productive waters.

Not all upwelling zones develop anoxic conditions. Oxic examples include off SE Brazil, the northern Pacific, and bordering Antarctica. The most likely reason for the lack of anoxicity is that the upwelling is only seasonal.

A diagnostic feature of sediments deposited under upwelling currents is a distinctive mineral assemblage including phosphorites and uranium minerals, as in the Neogene deposits of the Californian basins.

Prediction of ancient upwelling zones depends on the accurate reconstruction of atmospheric circulation and paleogeography. Occurrence of upwelling means significantly improved chances of source bed presence. Examples of source beds thought to have been deposited as a result of upwelling include the Permian Phosphoria Formation of western USA, the Triassic Shublick Formation of the North Slope, Alaska, the Cretaceous La Luna Formation of Venezuela/Colombia, the Upper Cretaceous Brown Limestone of Egypt, and the Miocene Monterey Formation of California.

The oceanic midwater oxygen minimum layer occurs in the world's oceans at depths of *c.* 100–1000 m. It is caused by the degradation of organic matter that has fallen from the overlying highly productive photic zone. Below this midwater zone, oxygen contents rise again because of the influence of cold, dense currents that originate in the polar regions and sweep along the ocean floors towards tropical latitudes. These currents supply oxygen that prevents the midwater oxygen minimum layer becoming anoxic, except in rare examples. The present-day Atlantic Ocean is well oxygenated because there is virtually no obstruction to the passage of cold polar waters from both its northern and southern ends. In contrast, in the eastern Pacific and northern Indian Oceans (Fig. 10.16), oxygen levels drop to less than 0.5 $ml\,l^{-1}$. Ocean floor currents reaching these areas have lost much of their oxygen, and the midwater oxygen minimum layer is free to intensify. TOCs in these areas range up to 11%.

The presence of strong ocean currents derived from the poles is a relatively recent feature of the world's oceans. At the present day, the Earth is in an interglacial phase. At times in the past, for example during most of the Mesozoic (particularly during the Late Jurassic and Mid-Cretaceous), the global climate was warmer, and the shape of the world's oceans was quite different from that of today. At this time, oceanic circulation may have been much more sluggish, and an intense midwater oxygen minimum zone may have developed. The Mid-Cretaceous "global anoxic events" probably occurred under such circumstances.

During times of high sea level, the midwater oxygen minimum zone may impinge on the continental shelf over wide areas. As a result, source beds are deposited on the continental shelf in association with reservoir and carrier beds, and a hydrocarbon play may be produced. Oxygen deficiency could be reinforced in bathymetric depressions in the broad epicontinental seas produced at this time. Sediments deposited in midwater anoxic zones

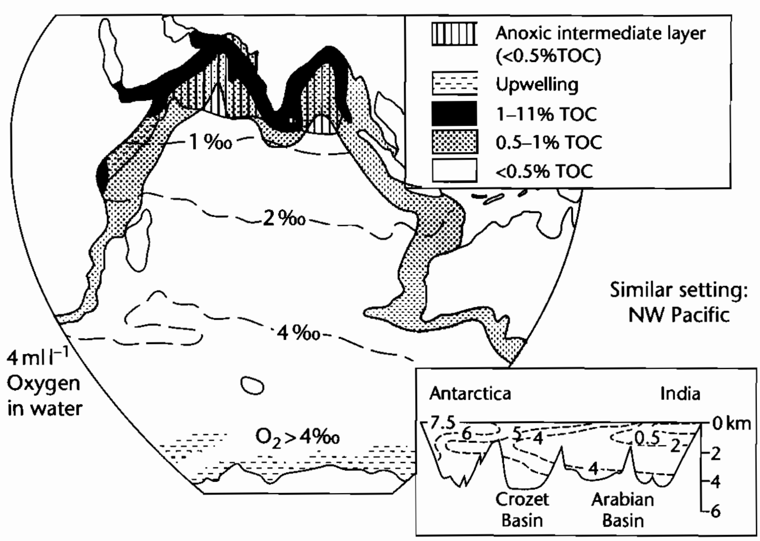


Fig. 10.16 Midwater oxygen concentrations and total organic carbon (TOC) concentrations in the Indian Ocean. TOCs are the highest around the Indian coastline where oxygen levels in the midwater layer fall to less than 0.5 $ml\,l^{-1}$ and impinge on the continental slope and shelf.

may be finely laminated, nonbioturbated, organic-rich, diatomaceous mudstones (Gulf of California) or olive grey muds (northern Indian Ocean). Examples of source rocks thought to have been deposited as a result of impingement of the midwater oxygen minimum zone on the continental shelf include the Toarcian source rocks of western Europe.

The optimum conditions for marine source bed deposition occur when one of the mechanisms is reinforced by another. For example, a silled geometry may combine with the midwater oxygen minimum zone, or the midwater oxygen minimum may be intensified by upwelling.

The gas- or oil-proneness of a marine source rock depends primarily on the presence or absence of gas-prone terrigenous plant material. Enclosed marine basins close to a major clastic source may be gas-prone. Oil-prone organic matter of truly marine origin occurs in upwelling zones offshore from arid land areas.

10.3.1.3 Detection and measurement of source rocks

A range of geochemical techniques has been developed to identify and measure source rocks and petroleum fluids. These techniques may be used initially to establish simply whether a source rock exists in the sediments being sampled, but a series of other important questions about the petroleum charge system operating in an area may also be addressed. The richness of a source rock and the petroleum type or composition likely to be expelled may be determined. The thermal maturity may also be measured. Source rocks and fluids may be correlated geochemically, so that migration routes can be interpreted. Detection and measurement of source rocks is therefore necessary for efficient exploitation of most known plays, and for the recognition of new conceptual plays.

Attempts have been made to identify mature source rock horizons on petrophysical wireline logs, such as the gamma ray, sonic, and resistivity logs. Detection generally depends on the occurrence of nonconductive petroleum in the pore space of the mature source rock, which makes it abnormally resistive, or on the overpressure that tends to be created by actively generating source rocks, which causes abnormally long sonic transit times. Source rocks have also been known to be abnormally radioactive compared to surrounding nonsource shales, and may therefore be detected on gamma ray logs. The Kimmeridgian "hot" shale of the North Sea is an example. There are numerous pitfalls, however, in the identification of source rocks on wireline logs, and potential source horizons should always be confirmed where possible by correlation with geochemical indicators.

Before outlining some routine geochemical and visual microscopic measurements on source rocks, it is necessary to understand the nature of the petroleum-bearing matter contained in source rocks, and the nature of petroleum itself. We have seen that petroleum is derived mainly from lipid-rich organic material buried in sediments. Most of this organic matter is in a form known as *kerogen*. *Kerogen* is that part of the organic matter in a rock that is insoluble in common organic solvents. It owes its insolubility to its large molecular size. Different types of kerogen can be identified, each with different concentrations of the five primary elements, carbon, hydrogen, oxygen, nitrogen and sulfur, and each with a different potential for generating petroleum.

The organic content of a rock that is extractable with organic solvents is known as *bitumen*. It normally forms a small proportion of the total organic carbon in a rock. Bitumen forms largely as a result of the breaking of chemical bonds in kerogen as temperature rises.

Petroleum is the organic substance recovered from wells and found in natural seepages. Bitumen becomes petroleum at some point during migration. Important chemical differences often exist between source rock extracts (bitumen) and crude oils (petroleum).

Crude oil is naturally occurring petroleum in a liquid form. The term black oil is sometimes used to indicate petroleum that is liquid at both reservoir and surface temperatures and pressures.

Natural gas is petroleum occurring in the gaseous phase. *Wet gas* is differentiated from *dry gas* in that it yields significant volumes of liquid (*condensate*) on changing from reservoir to surface conditions. When the condensate yield is potentially high, the fluid is called a *gas condensate*.

Under conditions of very low temperature and high pressure, *gas hydrates* may form. These are solid crystalline structures, usually containing methane. Methane hydrates may be found in arctic permafrost regions but also under the deep seafloor even in tropical latitudes.

Natural gas resulting from the thermal breakdown of kerogen is known as *thermogenic*. *Biogenic gas*, however, is a natural gas formed solely as a result of bacterial activity in the early stages of diagenesis (<60–70 °C). It normally occurs at shallow depths, and is always very dry.

Total organic carbon (TOC)

TOC is a measure of the carbon present in a rock in the form of both kerogen and bitumen. Typical values of TOC for different lithologies are shown in Table 10.3.

Shales tend to be more rich in organic matter than carbonates. TOC values in source rocks may be quite low, and are frequently <2%. Coals, however, may have TOCs of over 50%. 0.5% TOC is frequently taken as the minimum organic content for a shale source rock; a slightly lower value applies for carbonates. Below 0.5% TOC, not enough petroleum can possibly be generated to saturate the source rock; saturation must take place before expulsion can occur. Rocks with greater than 0.5% TOC are not, however, guaranteed as source rocks. If the organic carbon is inert, no amount of it will form a source rock.

Amount of soluble extract (bitumen)

The soluble extract of source rocks reflects oil content, and hence varies strongly with maturity. Figure 10.17 shows its variation with maturity for source rocks in four different basins; in each case it is strongly correlated with the onset of oil generation.

Rock pyrolysis

Espitalié developed a standard procedure for the pyrolysis of rock samples, known as Rock-Eval pyrolysis. About 100 mg of finely ground rock sample is placed into a furnace at 250 °C in an inert atmosphere and then raised to a temperature of 550 °C. The amount of hydrocarbon products evolved is recorded by a flame ionization detector (FID) as a function of time. Three peaks are typically recorded, known as the S_1, S_2, and S_3 peaks (Fig. 10.18). The S_1 peak represents hydrocarbons evolved at low temperatures – these represent free or adsorbed hydrocarbons (bitumen) that were already present in the rock before pyrolysis. The S_2 peak is produced at higher temperatures by the thermal breakdown of kerogen. Oxygen-bearing volatile compounds (carbon dioxide and water) are passed to a separate (thermal conductivity) detector, which produces an S_3 response. S_1, S_2, and S_3 are expressed as milligrams per gram of original rock (mg g^{-1}) or kilograms per tonne (kg t^{-1}).

Table 10.3 Average values of hydrocarbons, nonhydrocarbon bitumen, and organic carbon in ancient nonreservoir sediments (from Tissot and Welte 1978).

Origin	Type of rock	Number of samples	Extractable bitumen (ppm) HC	Extractable bitumen (ppm) non HC	Organic carbon (%)	Average HC Ave. org. C (mg g^{-1})	Author
200 formations from 60 sedimentary basins	shales	791	300	600	1.65	18	Hunt (1961)
	carbonates	281	340	400	0.18	151	Hunt (1961)
Rocks of various origins	shales	very large	180		0.9	20	Vassoevich et al. (1967)
	silts		90		0.45	20	Vassoevich et al. (1967)
	carbonates		100		0.2	50	Vassoevich et al. (1967)
Source rocks from 18 sedimentary basins	all types	668	860	780	1.82	47	Institut Francais du Pétrole (unpublished)
	shales and silts	418	930	810	2.16	43	
	calcareous shales	97	1260	1220	1.90	66	
	carbonates	118	335	440	0.67	50	
9 source rocks	not specified	not specified	267–2360		0.53–3.67	34–101	Philippi (1965)

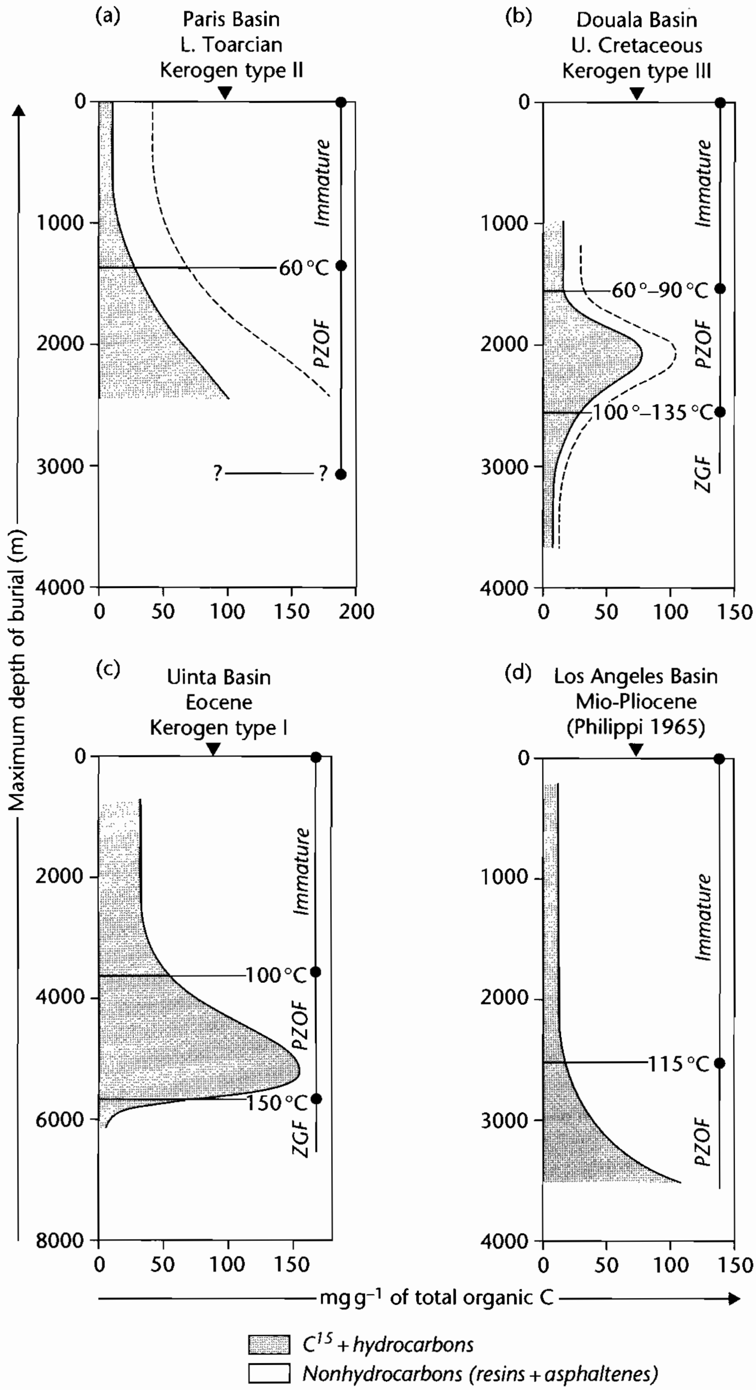


Fig. 10.17 Formation of hydrocarbons and nonhydrocarbons (resins and asphaltenes containing N, S, O) as a function of burial depth in different basins. For each basin, the temperatures that mark the upper and lower limits of the main oil generation zone (PZOF) are marked. Bitumen content clearly rises as the oil generation zone is entered, and diminishes as the underlying gas zone (ZGF) is approached. Bitumen content represents the oil content that can be dissolved from a rock, and this shows a strong correlation with its thermal maturity.

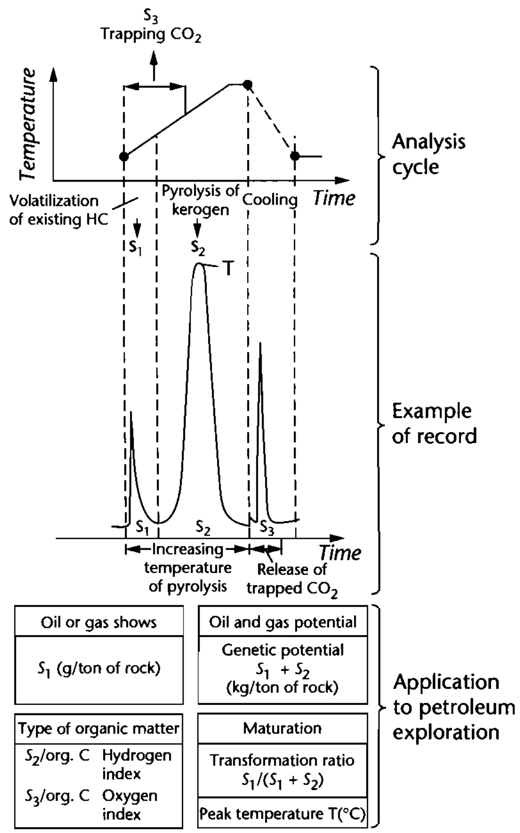


Fig. 10.18 Cycle of analysis and example of record obtained by the pyrolysis method of Espitalié et al. (1977) (after Tissot and Welte 1978). Three peaks are normally observed. The S_1 peak represents already existing bitumen. S_2 represents hydrocarbons generated from the thermal breakdown of kerogen. The S_3 response is produced by oxygen-bearing compounds released at high temperature. S_1 and S_2 can be used to assess oil-generating potential, whereas S_2 and S_3 can be used to calculate *hydrogen index* and *oxygen index*, which indicate kerogen type. The temperature corresponding to the S_2 peak, and the $S_1/(S_1+S_2)$ ratio indicate the level of thermal maturation.

The temperature at which the S_2 generation peak occurs is also recorded, and is an indicator of source maturity.

Rocks with (S_1+S_2) values of less than $2\,kg\,t^{-1}$ are considered as insignificant source rocks. Between $2\,kg\,t^{-1}$ and $5\,kg\,t^{-1}$ a significant amount of petroleum may be generated in the source rock but it may be too small to result in expulsion. If the source rock is raised to higher maturity, generated oil may be cracked to gas and expelled in the gas phase. Source rocks with values of $5–10\,kg\,t^{-1}$ have the potential to expel a proportion of their generated oil. Source rocks with greater than $10\,kg\,t^{-1}$ are considered rich; oil generated will almost certainly be in sufficient quantities to ensure expulsion. Exceptionally, yields of several hundred $kg\,t^{-1}$ are measured; these are usually from coals or oil shales.

The type of kerogen in the source rock is indicated by the *hydrogen index*, which combines the S_2 pyrolysis peak with TOC:

$$\text{Hydrogen index} = \frac{S_2}{TOC} \times 100\ \text{mg g}^{-1}\ {}^{\circ}\text{C}^{-1} \qquad (10.1)$$

It expresses the "usable" or pyrolysable fraction of the organic content. What is left is inert carbon, which is incapable of sourcing petroleum.

Hydrogen indices of <50 imply that the kerogen is made up predominantly of inert kerogen. Values of >200 suggest the presence of significant amounts of hydrogen-rich (oil-prone) kerogen. The hydrogen index may be as high as 900 in strongly oil-prone oil shales. The ratio of S_3 to TOC is known as the *oxygen index*. Tissot and Welte (1978) cross-plot hydrogen index and oxygen index in order to classify source rocks into three types, I, II, and III (Fig. 10.19), each of which has different petroleum generating characteristics.

Gas chromatography

Gas chromatography is a technique that separates the individual petroleum compounds in a petroleum mixture, according to increasing carbon number (Fig. 10.20). Gas chromatography can be performed on the products from pyrolysis (pyrolysates), on soluble extracts or on crude oil samples. From pyrolysis gas chromatography (PGC), the broadest application is in estimating the oil versus gas proneness of the kerogen. This can be determined by dividing the pyrolysate into gas (C_1–C_5) and liquid (C_{6+}) fractions. At a greater level of refinement, the gas chromatogram determines the detailed composition of the fluid for use in rock–rock, rock–oil, and oil–oil correlations.

Visual kerogen descriptions

The size, shape, structure, and color of kerogen fragments, once isolated from the rock, can be microscopically examined in *transmitted light*. Kerogen containing weakly translucent to opaque, structured fragments

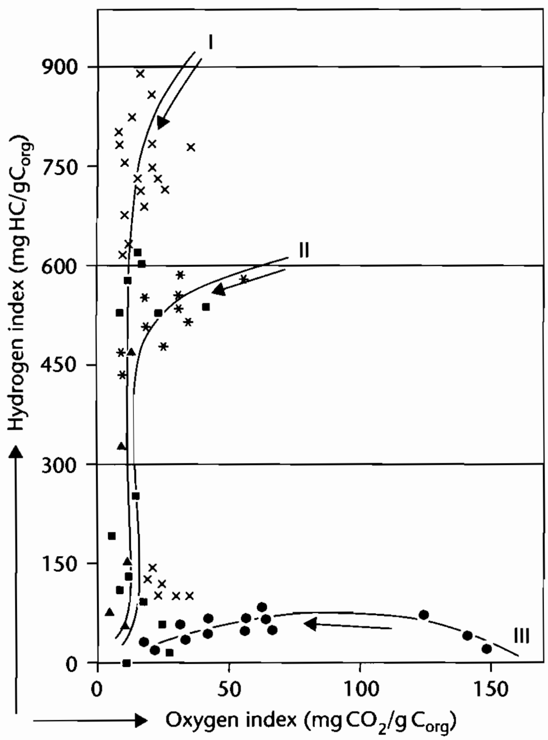


Fig. 10.19 Classification of kerogen types using hydrogen and oxygen indices. The diagram is readily comparable with the van Krevelen diagram plotted from elemental analyses of kerogen (Espitalié et al. 1977). Each kerogen type has different hydrocarbon-generating characteristics. Type I is the most oil prone whereas Type III produces mostly gas (after Tissot and Welte 1978).

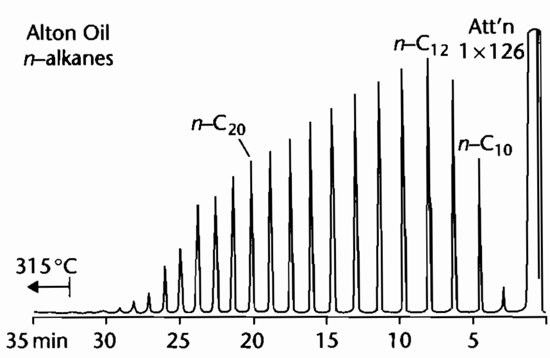


Fig. 10.20 Gas chromatogram of *n*-alkanes of an Australian crude oil. Each *n*-alkane compound in the oil is identified by a peak in the gas chromatogram.

recognizable as higher plants is sometimes referred to as *humic*, whereas translucent amorphous kerogen is called *sapropelic*. Translucent algae, spores, cuticles, pollen, and resin bodies may also be recognized on the basis of internal structure, shape, and color. The color of spores, pollen, and other microfossils has been found to be broadly related to thermal maturity: spore color changes from yellow, through orange to brown, and eventually black, as thermal maturity increases. Humic kerogen was formerly equated with gas-prone source rocks, and sapropelic kerogen with oil-prone source rocks, but this correlation is now known to be exceedingly unreliable. Certainly, not all sapropelic material is oil-prone.

Examination of kerogen particles in *reflected light* allows the definition of three major groups. In order of increasing reflectance, these are the *exinite* group, the *vitrinite* group and the *inertinite* group (§10.3.1.1). Figure 10.21 shows reflectance measurements on the organic particles in a mid-Liassic shale, illustrating the differing reflectances of the three main maceral groups.

The *fluorescence* of organic particles under ultraviolet light allows the identification of the liptinite group, which fluoresce strongly. The vitrinite and inertinite groups do not usually fluoresce.

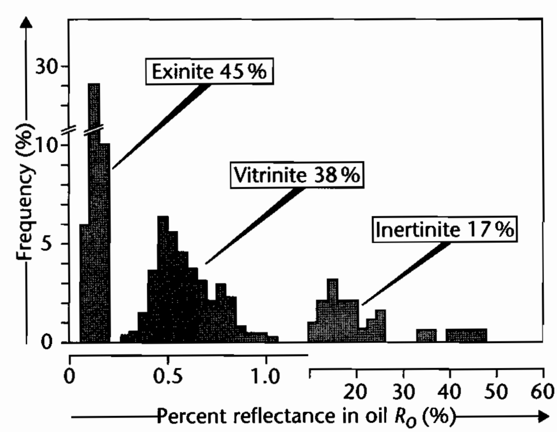


Fig. 10.21 Histograms showing reflectance measurements on different groups of kerogen particles. The exinite, vitrinite, and inertinite groups each have different ranges of reflectance. The reflectance of vitrinite is used as an index of thermal maturity (Ch. 9). Middle Liassic shale, Luxembourg, modified by Tissot and Welte (1978) from Hagemann (1974).

VITRINITE REFLECTANCE MEASUREMENTS

Vitrinite reflectance (§9.7.2) is the most widely used indicator of source rock maturity. Values measured on the different vitrinite particles present in a sample tend to vary widely (Fig. 10.21). To ensure reliable results, a reasonably large number of determinations (e.g., 20) need to be carried out on the same sample, and the mean calculated. Where a distribution of vitrinite reflectances is strongly bimodal, reworking of the higher reflectance group has probably taken place.

The vitrinite reflectance scale has been calibrated by other maturity parameters (§9.7.2) and by field studies in oil and gas provinces, so that R_o can be correlated with the main zones and thresholds of petroleum generation as follows:

$R_o<0.55$	Immature
$0.55<R_o<0.80$	Oil and gas generation
$0.80<R_o<1.0$	Cracking of oil to gas (gas condensate zone)
$1.0<R_o<2.5$	Dry gas generation

Vitrinite reflectance is a very good maturity indicator above about 0.7 or 0.8% R_o. An important use of vitrinite reflectance measurements in basin analysis is in calibrating thermal and burial history models with present-day maturity data (§9.7.2, §9.8.1).

10.3.2 The petroleum charge

Summary

A petroleum charge occurs when petroleum is generated in a source rock, is expelled, and migrates through a carrier bed to a trap.

Petroleum is chemically a mixture of saturated and aromatic hydrocarbons and NSO (nitrogen-sulfur-oxygen) compounds. A wide range of geochemical analyzes can be carried out on petroleum and source rock extracts that aim to relate the petroleum back to its original source rock and depositional environment. Important physical properties of petroleum are its density, formation volume factors, and boiling points; these influence secondary migration processes, subsurface volume changes, and phase behavior.

Petroleum generation takes place as a result of the chemical breakdown of kerogen with rising temperature. As hydrocarbons are released, the remaining kerogen evolves towards a carbon residue. Temperature and time are the most important factors affecting the breakdown of kerogen. The rate of breakdown can be calculated from the Arrhenius equation given in §9.5. The reactive fraction of kerogen can be subdivided into a labile portion, which yields chiefly oil, and a refractory portion, which yields mainly gas. Labile kerogen breaks down over approximately the 100–150 °C range, followed by refractory kerogen from 150–220 °C. Over the 150 to 180 °C range, oil is rapidly cracked to gas. Thus a stage of oil generation is succeeded by a stage of wet gas/gas-condensate generation, and finally by a stage of dry gas generation.

Petroleum expulsion is probably caused by microfracturing of the source rock after overpressure has built up as a result of hydrocarbon generation. Lean source rocks may not generate sufficient oil to cause expulsion. If raised to higher maturity, generated oil may be cracked to gas that will be efficiently expelled. For rich source rocks (>5 $kg\,t^{-1}$) efficiency of oil expulsion may be quite high (60–90%).

Secondary migration carries petroleum from the site of expulsion through porous and permeable carrier beds to sites of accumulation (traps) or seepage. The main driving force behind secondary migration is buoyancy, caused by the density difference between oil (or gas) and formation pore waters. The main restricting force is capillary pressure, which increases as pore sizes become smaller. During secondary migration, petroleum flows as slugs through the interconnected network of largest pores in the carrier bed, rather than sweeping its whole volume. Movement is stopped when a smaller pore system is encountered whose capillary pressure exceeds the upward-directed buoyancy of the petroleum column. This pore system constitutes a seal. The maximum petroleum column height that can be supported by a seal can be calculated.

Petroleum will tend to move in the true dip direction of the top of the carrier bed. Thus structural contour maps can be used to model migration pathways. During long distance migration, for example in some foreland basins, petroleum flow may be strongly focused along regional highs. Losses of petroleum during secondary migration are difficult to quantify.

Petroleum may be physically and chemically altered while it is in the trap by the processes of biodegradation, water-washing, deasphalting, and thermal alteration.

10.3.2.1 Some chemical and physical properties of petroleum

In order to understand petroleum generation, expulsion and migration, and the chemical changes that may take place in the trap, we need to know a little more about the chemical and physical properties of petroleum. Tissot and Welte (1978), Hunt (1979), and Kinghorn (1983) provide further details.

Hydrocarbons are compounds made up solely of hydrogen and carbon. Petroleum is usually a mixture of hydrocarbon compounds and other compounds containing additional substantial amounts of nitrogen, sulfur and oxygen, and other minor elements. There are three main groups of compounds found in petroleum (Fig. 10.22, Table 10.4):

- *Saturated hydrocarbons* are compounds in which each carbon atom is completely saturated with respect to hydrogen. Structures include simple straight chains of

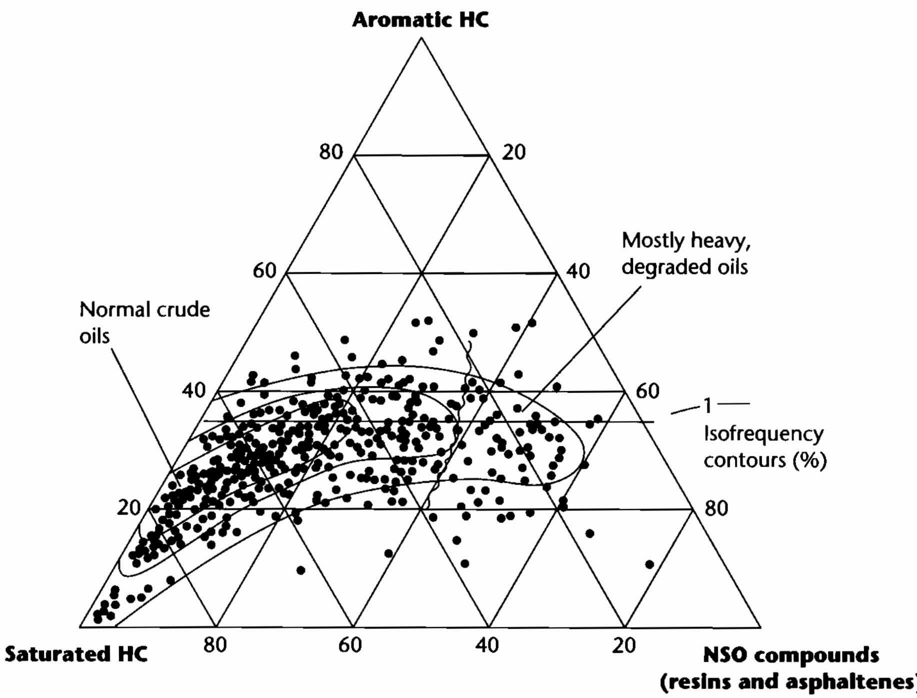


Fig. 10.22 Gross composition of 636 crude oils (from Tissot and Welte 1978) in terms of the three main groups of compounds found in petroleum – saturates, aromatics and NSO compounds. Normal (nondegraded) crudes typically contain 60–80% saturates, and less than 20% NSO compounds.

Table 10.4 Average composition of hydrocarbons (weight %) for a large number of crude oils (number of samples in brackets) (Tissot and Welte 1978, p. 342).

	Normal producible crude oils (517)	**All crude oils including tars (141)**	**Disseminated bitumen (668)**
n + iso-alkanes	33.3	31.7	27.7
Cyclo-alkanes	31.9	32.1	29.3
Aromatics	34.5	36.2	43.0
Saturated/aromatics	2.8	2.7	1.8
Alkanes/saturated	0.49	0.48	0.47

carbon atoms (the normal paraffins or normal alkanes), branched chains (the isoalkanes), and rings (cyclic hydrocarbons). Methane and ethane are examples of simple normal alkanes, and are commonly referred to as C_1 and C_2. For all normal alkanes, the subscript after the C refers to the number of carbon atoms in the molecule;

- *aromatic hydrocarbons* are a group of unsaturated hydrocarbons with cyclic structures, and include several important biomarker compounds that allow oils and source rocks to be correlated;
- *NSO compounds (resins and asphaltenes)* contain atoms other than carbon and hydrogen, predominantly nitrogen (N), sulfur (S), and oxygen (O). They are known as heterocompounds and are subdivided into the *resins* and the *asphaltenes*.

The composition of source rock bitumens tends to be different from crude oils – they contain fewer aromatic and saturated hydrocarbons and more resins and asphaltenes. These differences are probably due to important chemical changes that take place during migration.

Biomarkers are compounds found in crude oils and source rock extracts that can be unmistakably traced back to living organisms (Mackenzie 1984). The nature of the biological input to a sediment, and the chemistry of the depositional environment, give source rock extracts and expelled oils a characteristic "fingerprint," which is superimposed by the effects of diagenesis and maturation. These fingerprints may be geochemically recognized. Biomarker compounds may be used to assess thermal maturity (at low levels), and to correlate oils with source rock extracts.

Carbon isotope ($\delta^{13}C$) values (Fig. 10.23) of crude oils and source rock extracts may be used to distinguish marine from freshwater/terrestrial sources, and biogenic from thermogenic gases.

Crude oils may be classified to enable specific oil types to be directly related back to their source rocks. Such classification schemes use parameters such as oil density,

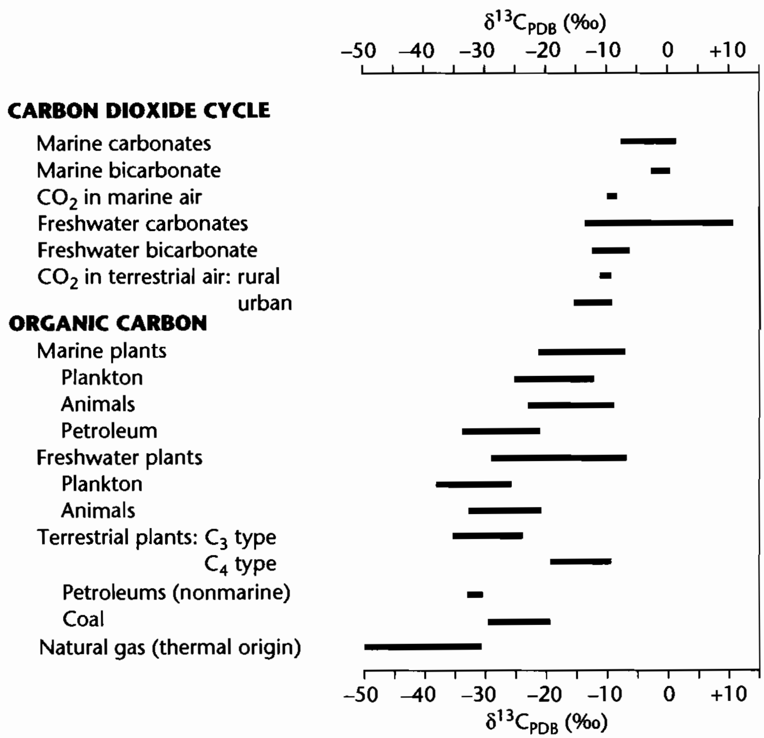


Fig. 10.23 Ranges of $\delta^{13}C$ values for various sources of organic and inorganic carbon *versus* PDB standard (after Waples 1981). Carbon isotope values can be used to distinguish marine from freshwater/terrestrial sources, and biogenic from thermogenic gas.

sulfur content, metals content, wax content, carbon isotope value, and pristane/phytane ratio. High sulfur contents (>1%) indicate marine sources, high wax content indicates land plant or freshwater algae sources, and high pristane/phytane ratios (>3) indicate land plant material as the source.

Oil density is normally quoted as an API (American Petroleum Institute) gravity

$$°API = \frac{141.5}{SG_{60}} - 131.5 \quad (10.2)$$

where SG_{60} is the specific gravity at 60 °F (15.6 °C). From equation (10.2), a fluid with a specific gravity of 1.0 has an API gravity of 10°. *Heavy oils* are those with API gravities of less than 20 (SG_{60} > 0.93). These oils have frequently suffered chemical alteration as a result of microbial attack (biodegradation) and other effects. Not only are heavy oils less valuable commercially, but they are considerably more difficult to extract. API gravities of 20–40° (SG_{60} 0.83–0.93) indicate *normal oils*. Oils of API gravity >40° (SG_{60} < 0.83) are *light*.

At surface conditions, normal oils are clearly less dense than water ($SG < 1$). However, under subsurface conditions, this density difference is much greater. Oil has a great capacity to contain dissolved gas at elevated temperatures. As a result, subsurface oil densities are typically in the 0.5–0.9 g cm^{-3} range. Subsurface pore water densities, in contrast, are typically 1.0–1.2 g cm^{-3}, and largely dependent on salinity. This density difference is the main driving force behind the secondary migration of petroleum.

Gas densities vary markedly between surface and subsurface conditions. At atmospheric pressure, the density of methane (C_1) is only 0.0003 g cm^{-3}, but at subsurface pressures of 5000 psi (1 MPa = 10 bars = 145 lb in^{-2} (psi)), equivalent to depths of 3–4 km, typical natural gas mixtures have densities of approximately 0.2–0.4 g cm^{-3}. In the subsurface, therefore, oils and gases take on more similar physical properties. Methane is the lightest of the hydrocarbon gases, and is normally the most abundant. Dry gases typically have methane concentrations of over 95%.

Formation volume factors relate the subsurface volumes of oil or gas to the volumes occupied at surface under standard conditions of temperature and pressure (60 °F and 14.7 psi). These factors must be estimated in order to calculate the potential recoverable reserves of an exploration prospect. Gas expands enormously on release of subsurface pressure, and may occupy several hundred times its subsurface volume at surface. The relationship between subsurface and surface volumes is given by

$$\text{Gas expansion factor} = \frac{P_r T_s Z}{T_r P_s} \quad (10.3)$$

where P_r and P_s are the pressures at reservoir (subsurface) and standard (surface) conditions respectively (psi), T_r and T_s are the temperatures at reservoir and standard conditions respectively (°Rankine = °F + 460) (the Rankine scale begins at absolute zero but has units equal to the Fahrenheit scale), and Z is termed the *gas deviation factor* (frequently close to 1.0).

Oil shrinks on movement to the surface, owing to the release of dissolved gas. Oil shrinkage factors vary from nearly 1.0 for shallow oils with almost no dissolved gas, to 2.0 or more for extremely gassy oil in deep reservoirs.

The boiling point of a petroleum compound is the temperature above which it is in a vapor state. At temperatures below its boiling point, the compound is in a liquid state. C_1 (methane) to C_4 (butane) are the only hydrocarbon compounds that are gases (vapors) at surface temperature and pressure. The other compounds are liquids.

Phase changes may take place in the subsurface during the processes of hydrocarbon generation, migration, and entrapment. These may be important in prospect and play assessment. Liquids may condense out of a petroleum vapor as it migrates through a carrier bed into areas of lower pressure. These valuable liquids may be lost as a residual oil saturation in the pores of the carrier bed. If an oil accumulation is uplifted as a result of, for example, inversion tectonics or thrust tectonics, large quantities of gas may be exsolved from the oil. This may cause displacement of oil from the trap.

10.3.2.2 Petroleum generation

Chemical changes to kerogen during source rock maturation

At shallow depths of burial of only a few hundred meters kerogen remains relatively stable. At greater depths of burial, however, under conditions of higher temperature and pressure, it becomes unstable and rearrangements take place in its structure in order to maintain thermodynamic equilibrium. Structures that prevent the parallel arrangement of cyclic nuclei are progressively eliminated. By this process, a wide range of compounds are generated (heteroatomic compounds, hydrocarbons, carbon dioxide, water, hydrogen sulfide, etc.), as the kerogen evolves towards a highly ordered graphite structure. Petroleum generation is, therefore, a natural consequence of the adjustment of kerogen to conditions of increased temperature and pressure.

Kerogen is a complex macromolecule composed of nuclei linked by heteroatomic bonds or carbon chains that are successively broken as temperature increases. As breakdown occurs, the first products released are heavy heteroatomic compounds, carbon dioxide, and water. These are followed by progressively smaller molecules, including hydrocarbons. The kerogen left behind becomes progressively more aromatic and evolves towards a carbon residue.

Mackenzie and Quigley (1988) classify kerogen into *reactive kerogen* and *inert kerogen* (Fig. 10.24). Reactive kerogen is transformed into petroleum at elevated temperatures, whereas inert kerogen rearranges towards graphite-like structures without the generation of petroleum. Reactive kerogen is subdivided into a labile portion which is transformed into petroleum that is chiefly oil at surface, and a refractory portion that generates chiefly gas.

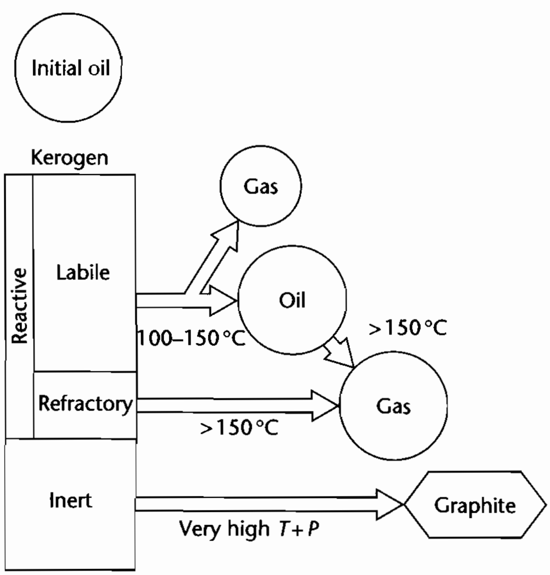


Fig. 10.24 Classification and fate of organic matter in source rocks. Kerogen is divided into reactive and inert portions. Inert kerogen rearranges towards graphite-like structures at very high temperatures (T) and pressures (P) without generating petroleum. Reactive kerogen is subdivided into a refractory part that yields mainly gas, and a labile portion that is transformed into petroleum, which is chiefly oil at the surface. Initial oil corresponds to bitumen normally present in immature source rocks. Relative amounts of initial oil, labile, refractory, and inert kerogen are determined by the nature of the precursory organisms and the depositional setting of the host source rock (after Mackenzie and Quigley 1988).

Kinetic models of kerogen breakdown

We have seen in §9.5 that temperature and time are the most important factors in controlling the maturation of organic matter. The complex series of consecutive reactions that cause kerogen breakdown proceed at varying rates, governed primarily by temperature and the activation energy of the particular reaction, and expressed in the *Arrhenius equation* (equation 9.40). If the constants in the Arrhenius equation are known for a particular petroleum-forming reaction, the rate at which it will proceed may be determined as a function of temperature, and the temperature range over which the bulk of the reaction will take place (before the raw material is used up) can be calculated. Masses of petroleum generated as a result of kerogen breakdown can also be calculated as a function of temperature, and hence, if the subsidence and thermal history of an area are known, as a function of geological time.

The activation energies of each individual reaction are not exactly known, but for each kerogen type a distribution of activation energies can be established from laboratory and field studies. These distributions, together with the other parameters in the Arrhenius equation, can be used to model kerogen breakdown and the associated generation of petroleum products for each kerogen type.

The kinetic model of Mackenzie and Quigley (1988) shows that kerogen concentrations diminish with increasing temperature for a range of heating rates (Fig. 10.25). Separate sets of curves are shown for labile and refractory kerogen. The heating rate parameter incorporates the time factor in source rock maturation, which is known to be important from the occurrence of generally shallower oil generation thresholds in older basins (Dow 1977). Depending on heating rate, kerogen breakdown into petroleum takes place largely over the 100–150 °C range for labile kerogen. For refractory kerogen, the range is approximately 150–220 °C.

Any oil left in a source rock from the breakdown of labile kerogen will be cracked to gas if temperatures continue to rise above 150 °C, and most cracking reactions take place over the 150–180 °C range (Mackenzie and Quigley 1988). The time required to crack half the

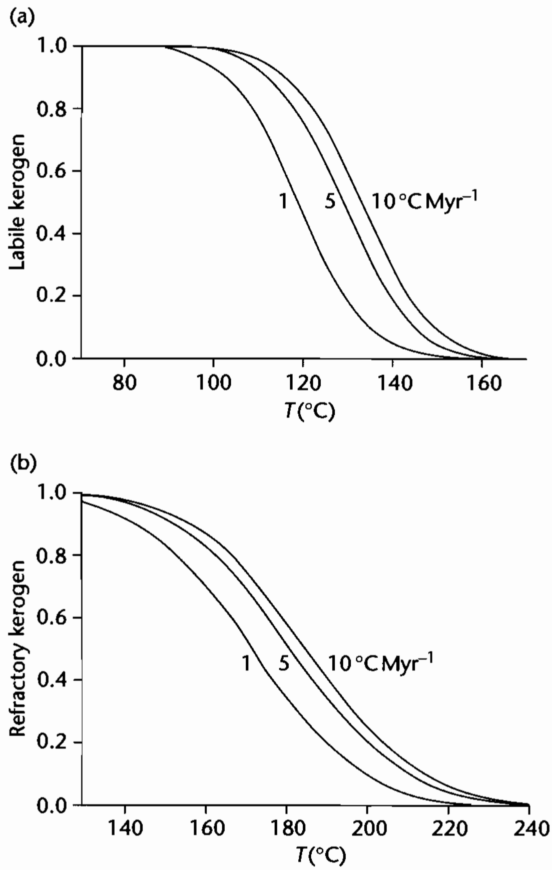


Fig. 10.25 Calculated concentrations of reactive labile (a) and refractory (b) kerogens, relative to initial amount of reactive kerogen, as a function of maximum temperature for the range of heating rates shown. Mean heating rates of about 0.5°C Myr^{-1} occur in old stretched basins. Mean heating rates of about 10°C to 50°C Myr^{-1} occur in young (<25 Myr) stretched basins. Labile kerogen breaks down generally over the 100–150°C range. Refractory kerogen, however, breaks down at much higher temperatures, from about 150–200°C. After Mackenzie and Quigley (1988).

mass of oil to gas (the "half-life" of oil), if held at a constant temperature of 180 °C, is less than a million years. Consequently, at temperatures above 160 °C, oil would not be expected to exist for geological periods of time. The cracking process applies, of course, to oil accumulations as well as to oil remaining in source rocks. As a result, oil fields will not exist at depths greater than those corresponding approximately to the 160 °C isotherm.

The kinetic model predicts that a number of stages of petroleum formation succeed each other without significant overlap (Figs 10.26, 10.27). The immature stage precedes petroleum generation (the *diagenesis stage* of Tissot and Welte 1978). It is followed by a stage of oil and gas generation from labile kerogen containing lipid material (exinitic macerals), and a stage of wet gas/gas condensate generation resulting from the cracking of previously generated oil, together making up the *catagenesis* stage. Finally, there is a stage of dry gas generation from refractory (vitrinitic) kerogen, called the *metagenesis stage*. Methane is the main petroleum product.

Some heavy heteroatomic (NSO) compounds, together with carbon dioxide and water, are generated in the immature (diagenesis) stage of kerogen evolution, but there is effectively no hydrocarbon generation. Hydrocarbons present in rocks of this maturity are inherited from their precursor organisms (biomarkers, or geochemical fossils) and have not been generated from kerogen. During the main zone of oil formation, hydrocarbon compounds (normal and iso-alkanes, cycloalkanes, and aromatics) are generated; the proportions of each depends on kerogen type. As maturity increases, low molecular weight hydrocarbons become most abundant, until only methane is present.

10.3.2.3 Expulsion from the source rock

Mechanics

Expulsion is also known as *primary migration*.

As a result of the compaction of source rocks during burial, pore sizes may become smaller than the size of some petroleum molecules (Fig. 10.28). This presents a difficulty in explaining how petroleum migrates out of the source rock. Of all the possible mechanisms of primary migration debated in the geological literature, the most likely appears to be as a discrete phase through microfractures caused by the release of overpressure. The cause of the overpressure in the source rock may be a combination of oil or gas generation, fluid expansion on temperature increase, compaction of sealed source rock units, or release of water on clay mineral dehydration.

The conversion of kerogen to petroleum results in a significant volume increase. This causes a pore pressure build-up in the source rock. The pressure build-up is sometimes large enough to result in microfracturing. This

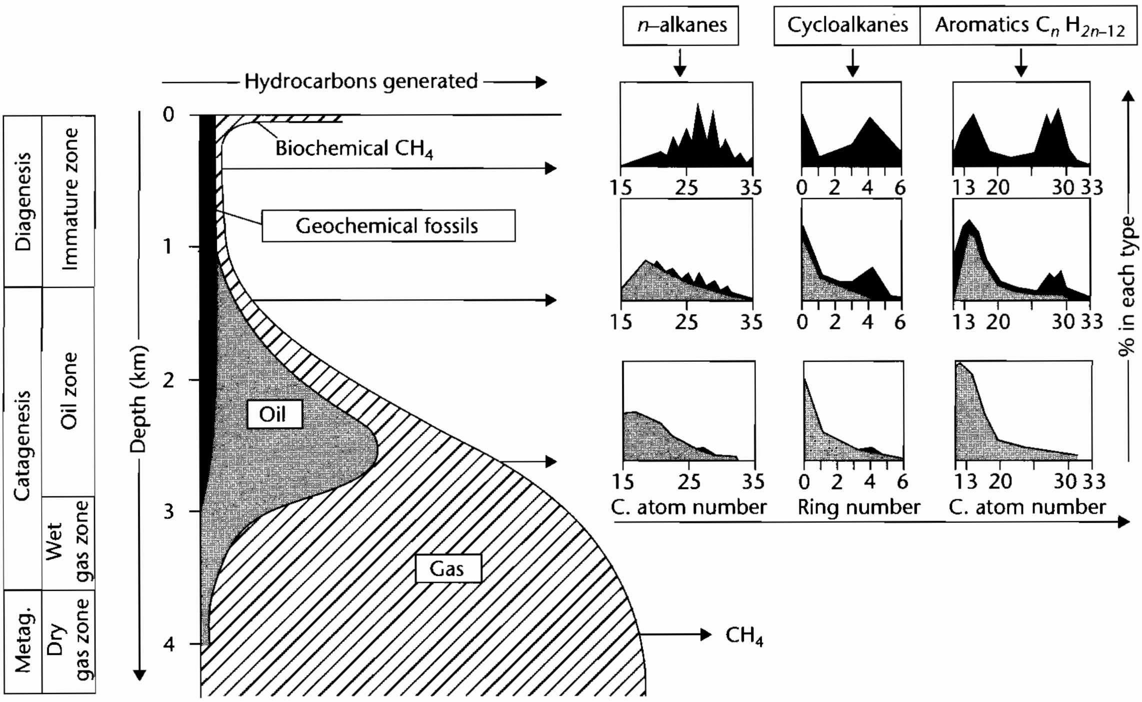


Fig. 10.26 General scheme of hydrocarbon formation as a function of burial of the source rock, according to Tissot and Welte (1978). As formation temperature rises on progressive burial, an immature stage is succeeded by stages of oil generation, oil cracking (wet gas stage), and finally dry gas generation. Typical distributions of *n*-alkanes, cycloalkanes, and aromatics at three points in this general evolution are shown.

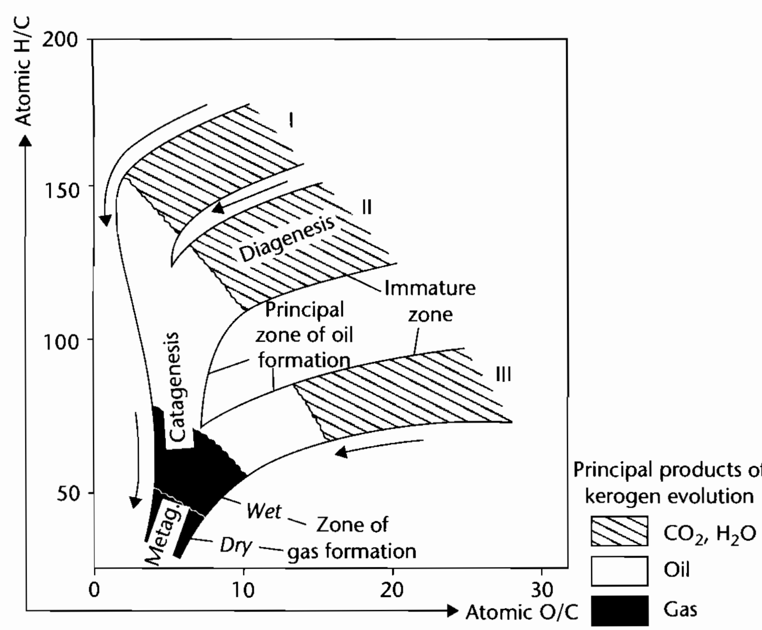


Fig. 10.27 General scheme of kerogen evolution presented on van Krevelen's diagram. The diagenesis, catagenesis, and metagenesis stages are indicated and the principal products generated during that time are shown (after Tissot 1973).

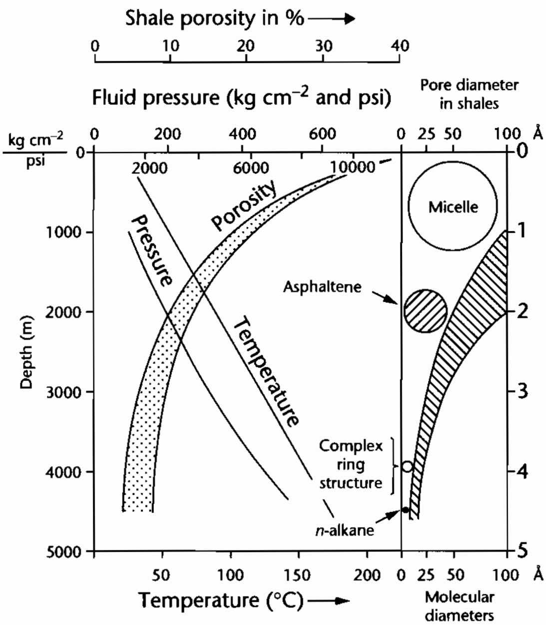


Fig. 10.28 Interrelationship of various physical parameters with increasing depth of burial for shale-type sediments, showing shale pore diameters in relation to the molecular diameters of the petroleum. At moderate depths of burial, shale pore diameters typically become very small in relation to the larger petroleum molecules.

releases pressure, and allows the migration of petroleum out of the source rock and into adjoining carrier beds, from which point secondary migration processes take over. Cycles of petroleum generation, pressure build-up, microfracturing, petroleum migration, and pressure release continue until the source rock is exhausted. The implication of this theory is that mature source rocks will always expel petroleum as long as they are rich enough. In this sense, primary migration is not a major concern for the practicing petroleum geologist. Primary migration clearly takes place both upwards and/or downwards out of the source beds, as governed by local pressure gradients.

A large volume expansion takes place when petroleum liquids are cracked to gas within the source rock. A lean oil-prone source rock may not generate sufficient hydrocarbons to cause microfracturing. As a result, no expulsion will occur. If raised to higher maturity, however, the oil that has remained in the source rock will be cracked to gas. The resulting volume increase and overpressure may allow expulsion to occur. Thus, lean oil-prone source rocks tend to expel gas condensate once they are raised to sufficiently high maturity.

Efficiency of expulsion

How much of the generated (plus initial) petroleum is likely to be expelled from the source rock? Cooles et al. (1986) have shown that, between 120 and 150 °C, petroleum expulsion efficiency is strongly dependent on the original richness of the source rock. In some rich source rocks (potential >5 kg ton^{-1}, TOC > 1.5%) oil expulsion may be very efficient, with 60–90% of the total petroleum generated being expelled. There is a lag, however, between petroleum generation and petroleum expulsion. It appears that a certain minimum petroleum saturation (probably about 4%) in the source rock is required before efficient expulsion takes place. In leaner source rocks (<5 kg ton^{-1}, <1.5% TOC) expulsion efficiency is much lower, and most of the oil generated remains in the source rock. As we have seen, if raised to higher maturity, it may be cracked to gas and expelled. Expulsion appears to be very efficient for gas or gas condensate, irrespective of original source richness.

Mackenzie and Quigley (1988) have classified source rocks into three end-member classes on the basis of initial kerogen concentration and kerogen type (Fig. 10.29). These parameters determine the timing and composition of the petroleum expelled. The *Petroleum Generation Index* (PGI) is the fraction of petroleum-prone organic matter that has been transformed into petroleum, and is thus a measure of source maturity. *Petroleum Expulsion Efficiency* (PEE) is the fraction of petroleum fluids formed in the source rock that has been expelled.

A *Class 1* source rock has predominantly labile kerogen at concentrations of >10 kg ton^{-1}. Generation starts at about 100 °C as the labile kerogen generates an oil-rich fluid. This rapidly saturates the source rock, and between 120 and 150 °C, 60–90% of the petroleum is expelled as oil with dissolved gas. The remaining fluid is cracked to gas at higher temperatures and expelled as a gas phase initially rich in dissolved condensate. Examples of Class 1 source rocks are the North Sea Kimmeridge Clay, and the Bakken Shale of the Williston Basin, Canada–USA.

Class 2 source rocks are a leaner version of Class 1, with initial kerogen concentrations of <5 kg ton^{-1}. Expulsion is very inefficient up to 150 °C because insufficient oil-rich petroleum is generated. Petroleum is expelled mainly as gas condensate formed by cracking above 150 °C, followed by some dry gas.

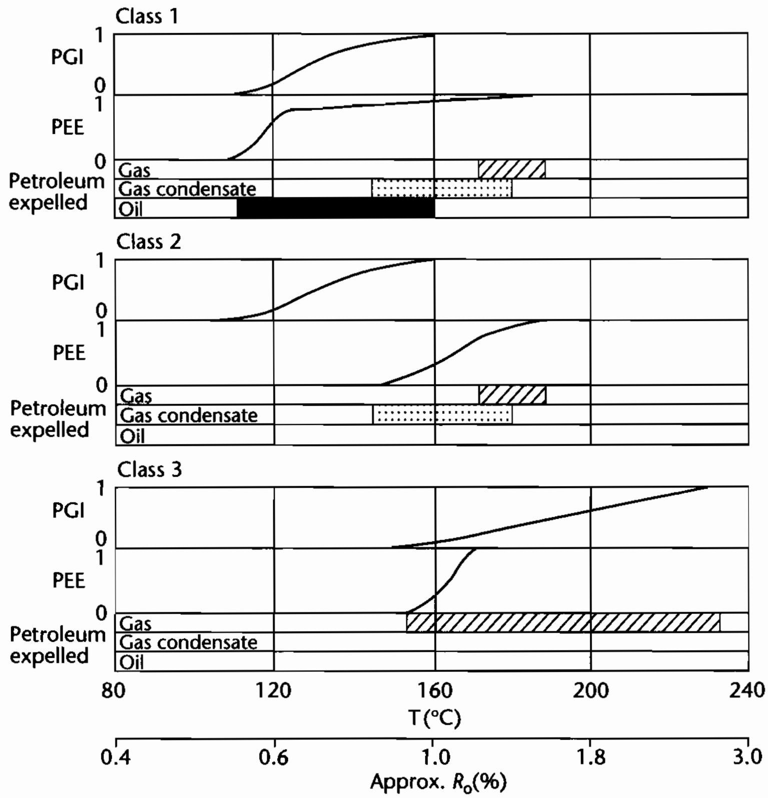


Fig. 10.29 Petroleum Generation Index (PGI) and Petroleum Expulsion Efficiency (PEE) as a function of maximum temperature for three classes of source rock, according to Mackenzie and Quigley (1988). Principal petroleum phases expelled over relevant temperature ranges are shown. Curves were constructed assuming a mean heating rate of 5°C Myr^{-1}. PGI is the fraction of petroleum-prone organic matter that has been transformed into petroleum. PEE is the fraction of petroleum fluids generated in the source rock that have been expelled. Class I are rich source rocks containing mainly labile kerogen. Class II are lean source rocks comprising labile kerogen. Class III source rocks contain mostly refractory kerogen.

Class 3 source rocks contain mostly refractory kerogen. Generation and expulsion takes place only above 150°C, and the petroleum fluid is a relatively dry gas.

Some formations contain mixtures of different source rock classes.

10.3.2.4 Secondary migration: through carrier bed to trap

Introduction

Secondary migration concentrates subsurface petroleum into specific sites (traps) where it may be commercially extracted. The main difference between primary migration (out of the source rock) and secondary migration (through the carrier bed) is the porosity, permeability, and pore size distribution of the rock through which migration takes place. These parameters are all much higher for carrier beds. As a result, the mechanics of migration may be quite different. The end points of secondary migration are the trap or seepage at surface. If a trap is disrupted at some time in its history, its accumulated petroleum may re-migrate either into other traps, or leak to the surface. The same processes of secondary migration apply to the re-migration as to the original migration into the trap.

A knowledge of the mechanics of secondary migration is important in the general understanding of active charge systems, but specifically in tracing and predicting migration pathways (hence in defining areas receiving a petroleum charge), in interpreting the significance of subsurface petroleum shows and surface seepages, and in estimating seal capacity in both structural and stratigraphic traps.

The mechanics of secondary migration are now well studied and well understood (Hubbert 1953; Gussow 1954; Berg 1975; Schowalter 1976). In the following section we describe secondary migration in terms of the main driving forces and the main restricting forces. The main driving forces are *buoyancy*, caused by the density difference between oil (or gas) and the pore waters of carrier beds, and *pore pressure gradients*, which attempt to move all pore fluids (both water and petroleum) to areas of lower pressure. The latter is known as a *hydrodynamic* condition. The main restricting force to secondary migration is *capillary pressure*, which increases as pore sizes become smaller. When capillary pressure exceeds the driving forces, entrapment occurs.

Driving forces in secondary migration

Buoyancy is a vertically directed force caused by the difference in pressure between some point in a continuous petroleum column and the adjacent pore water. It is a function of the density difference between the petroleum and the pore water, and the height of the petroleum column (Fig. 10.30):

$$\Delta P = Y_p g(\rho_w - \rho_p) \tag{10.4}$$

where ΔP is the buoyant force, Y_p is the height of petroleum column, g is acceleration due to gravity, and ρ_w and ρ_p are the subsurface densities of water and petroleum respectively. Under *hydrostatic conditions*, buoyancy is the only driving force in secondary migration. Under *hydrodynamic conditions* (that is, when water flows through a carrier bed), however, the driving force is modified. Hydrodynamics may either assist or inhibit secondary migration, depending on whether it acts with or against the buoyancy force. Hydrodynamics may be important in a number of respects: (i) by affecting the directions and rates of secondary migration, (ii) by increasing or decreasing the driving pressures against vertical or lateral seals, thus reducing or increasing the heights of the petroleum columns that the seals can withstand, and (iii) by tilting petroleum water contacts and displacing petroleum accumulations (for example, off the crests of structural closures).

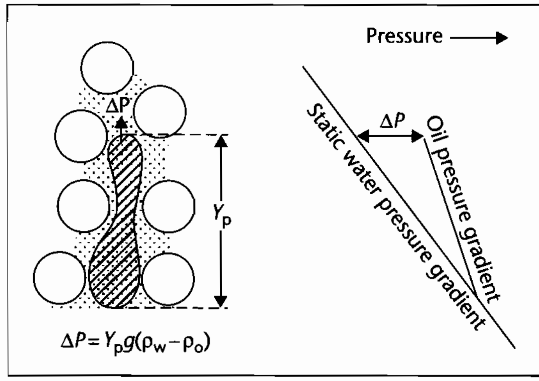


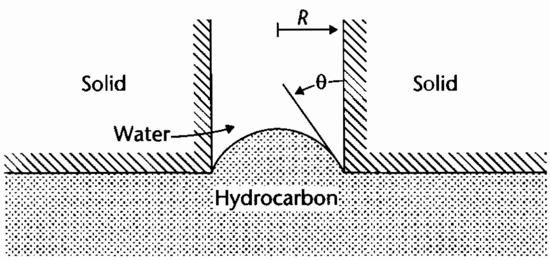
Fig. 10.30 Buoyancy as a driving force in secondary migration. Buoyancy is the pressure difference between a point in the petroleum column and the surrounding pore water. It is a function of the petroleum/water density difference and the height of the petroleum column. A large buoyancy pressure may develop at the tops of large, low-density (gas) petroleum columns. Pressure measurements at points throughout the petroleum column define a petroleum pressure gradient; this intersects the hydrostatic gradient at the petroleum–water contact.

The effect of hydrodynamics on rates and directions of secondary migration may be safely ignored except in basins where there is good evidence of hydrodynamics operating at the present-day. Without this evidence, it is difficult to support a strong argument for hydrodynamics having operated during secondary migration. Geologically long-lasting hydrodynamic conditions are most likely to have existed in foreland basins (see §9.6.3).

Restricting forces in secondary migration

When a petroleum globule or slug moves through the pores of a rock, work has to be done to distort the globule and squeeze it through the pore throats (Fig. 10.31). The force required is called capillary pressure (or displacement, or injection pressure), and it is a function of the size (radius) of the pore throat, the interfacial surface tension between the water and the petroleum, and the wettability of the petroleum–water–rock system:

$$\text{Displacement pressure} = \frac{2\gamma\cos\Theta}{R} \tag{10.5}$$



$p_d = \dfrac{2\gamma \cos\theta}{R}$

where p_d = Displacement pressure
γ = Oil–water interfacial tension
θ = Contact angle of oil and water against the solid
R = Radius of the pore throat

As γ increases p_d increases
As θ decreases p_d increases
As R decreases p_d increases

Fig. 10.31 Resistant forces in secondary hydrocarbon migration. Higher pressures are needed to force petroleum globules through smaller pores (after Purcell 1949 in Schowalter 1976).

where γ is the interfacial tension between petroleum and water (dyne cm^{-1}), Θ is the wettability, expressed as the contact angle of the petroleum–water interface against the rock surface (degrees), and R is the radius of the pore (cm). Higher pressures are needed to force petroleum globules through smaller pores.

Interfacial tension depends on the properties of the petroleum and water, and is independent of the rock characteristics. It is a function primarily of the composition of the petroleum (it is smaller for light, low viscosity oils), and temperature (interfacial tension generally decreases with increasing temperature). The effects of pressure and water chemistry are less important. For a given petroleum composition, therefore, interfacial tension may be considered effectively constant over large parts of the migration pathway, unless considerable vertical migration takes place. Gas–water interfacial tensions are in fact generally higher than those for oil–water. This means that, for the same rock, displacement pressures are higher for gas than for oil. The buoyancy pressures, however, are normally greater for gas.

Wettability is a function of the petroleum, water, and rock. Most rock surfaces are "water-wet" and Θ may be taken to be zero. In carrier beds along secondary migration routes, and in lateral and vertical seals to petroleum accumulations, the $\cos\Theta$ term in equation (10.5) can be ignored so that:

$$\text{Displacement pressure} = \frac{2\gamma}{R} \qquad (10.6)$$

Some of the grains of oil-filled reservoir rocks may be oil-wet, and organic-rich source rocks may also be partly oil-wet. Displacement pressures in these cases could, as a result, be considerably smaller than in water-wet rocks. This would assist oil migration.

Pore sizes are the most important control on secondary migration and entrapment. Pore sizes can be estimated visually (in thin section, or by scanning electron microscope, for example) in reservoir/carrier bed lithologies. Ideally, displacement pressure can be measured directly by mercury injection techniques for both reservoir and potential sealing lithologies. The principle of this technique is that a nonwetting fluid (mercury) is injected into a core plug and its saturation as a percentage of pore volume (cumulative volume of mercury injected) is recorded as a function of steadily increasing injection pressure (Fig. 10.32). The pressure at which mercury first begins to saturate the pores of the rock is the displacement pressure. This takes place when the *largest* pores are invaded. Thereafter, at higher pressures, the smaller pores are successively invaded. Mercury injection pressure can be easily converted to petroleum–water displacement pressure.

Once the displacement pressure has been overcome, and a connected petroleum slug is established in the largest pores of the rock, secondary migration may take place. One of the interpretations made from mercury capillary test data is that the petroleum saturation required to produce this connected petroleum slug is surprisingly small. In a series of experiments reported by Schowalter (1976), this critical saturation for a range of rock types varied from 4.5 to 17%, and averaged 10%. Active secondary migration pathways may therefore be characterized by petroleum saturations of only about 10%. Such low saturations provide weak shows that frequently go undetected or are considered of no significance.

Since it is the network of largest pores that controls displacement pressure (and hence secondary migration and seal potential), care should be taken that the rock material analyzed is representative of the carrier bed or potential seal as a whole. If larger pore systems exist in the carrier bed or potential seal than were analyzed in the injection tests, displacement pressures may be seriously overestimated.

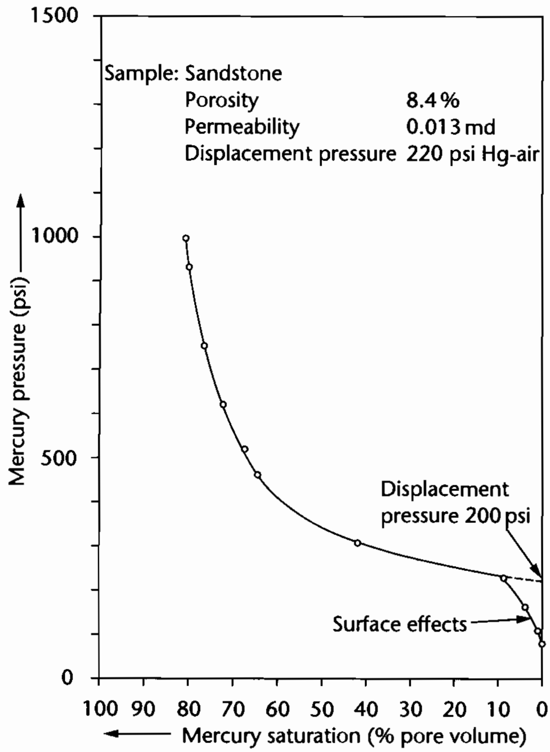


Fig. 10.32 Typical mercury capillary pressure curve. Mercury first begins to saturate the pores of the rock when the largest pores are invaded (the displacement pressure). A relatively small further increase in pressure commonly results in rapid saturation of the pore space and the establishment of a connected petroleum slug that may migrate through the rock. As little as 10% oil saturation may be required before secondary migration takes place (after Schowalter 1976).

So far we have considered only the entry of petroleum into a pore network from an infinite body (Fig. 10.31). Within the pore network of a rock, the pore throat radii at both upper and lower ends of the oil globule need to be considered (Fig. 10.33), and the capillary pressure equation is modified to:

$$\text{Capillary pressure} = 2\gamma\left(\frac{1}{r_t} - \frac{1}{r_b}\right) \tag{10.7}$$

where r_t is the radius of upper pore throat and r_b is the underlying pore radius.

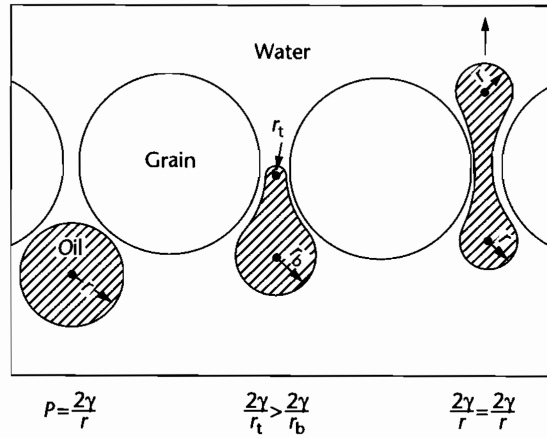


Fig. 10.33 Transport of an oil globule through pore throats in a water-wet subsurface environment. Capillary pressure opposes the buoyant force until the radius of curvature inside the distorted oil globule is equal at its lower and upper ends. The oil globule may then pass through the pore throat. After Berg (1975) in Tissot and Welte (1978).

Petroleum column heights and seal potential

Once a petroleum slug has entered a pore system of a constant size it will continue to move. Its rate of movement is governed by the driving forces and the permeability of the rock. When a smaller pore system is encountered, the driving forces may not be sufficient to overcome the increased capillary pressure. In this case, movement into the smaller pore network will not take place. The slug will either migrate away laterally (in a dipping carrier bed), using the larger pore system, or remain trapped. If joined by a large number of other petroleum slugs, a sufficient vertical column of petroleum may build up to provide a large, buoyant force that is enough to cause invasion of the finer pore network. Thus, a seal may be effective only up to a *critical petroleum column height*, at which point it leaks.

The critical petroleum column height (Y_{pc}) is given by

$$Y_{pc} = \frac{2\gamma\left(\frac{1}{r_t} - \frac{1}{r_b}\right)}{g(\rho_w - \rho_p)} \tag{10.8}$$

When the pore size of a sandstone reservoir r_b is very large in relation to the very small pore throat size r_t of a shale caprock, the $1/r_b$ term becomes relatively very small and equation (10.8) can be simplified to:

$$r_{pc} = \frac{2\gamma}{r_t g(\rho_w - \rho_p)} \tag{10.9}$$

Since the subsurface density of gas is less than that of oil, it is clear that seals can support much larger oil columns than gas columns. This has important implications for migration and entrapment. For example, it may prevent the formation of gas caps overlying oil columns. It also suggests that gas should migrate vertically more successfully than oil.

In order to calculate seal potential, we need to know the pore radius that is relevant to leakage. This should be the smallest pore throat in a network of large pores that, if penetrated, would allow an interconnected petroleum slug to be established. This is clearly not the largest pore throat, nor the smallest, but somewhere in between! It may be approximated by a mean hydraulic radius, r_h, where

$$r_h = 2.8(K/\phi) \tag{10.10}$$

where K is permeability and ϕ is porosity. The difficulty of estimating the critical pore radius of the caprock renders seal capacity calculations subject to wide ranges of error. They may frequently give only order of magnitude estimates.

Faults and fractures

Fault zones can act as both conduits and barriers to secondary migration (Jones et al. 1998). The material crushed by the frictional movement of the fault, the fault gouge, is frequently impermeable and does not allow the passage of petroleum. Clay smeared along fault planes, as in the growth faults of the Niger delta (Weber et al. 1978) and in the Louisiana Gulf Coast region (Smith 1980; Lopez 1990), also blocks petroleum migration. Fractures formed in either the footwall or hangingwall, if they remain open, may form effective vertical migration pathways. This is unlikely except at shallow depths, but may occur in the uplifted hangingwalls of contractional (thrust) faults on release of compressive stresses. Tensional fractures in the crestal zones of anticlinal structures may also allow migration of petroleum. Lateral migration will tend to be inhibited by the presence of faults, since they interrupt the lateral continuity of the carrier bed.

The sealing qualities of fault zones are discussed further in §10.6 on petroleum traps.

Migration pathways

Since the driving force behind secondary migration (in the absence of hydrodynamics) is buoyancy, it is clear that petroleum will tend to move in a homogeneous carrier bed in the direction of steepest slope. This is perpendicular to its structural contours, that is, in the true dip direction. Lines drawn at right angles to the structural contours of the top carrier bed/base seal horizon are known as *orthocontours*. Orthocontour maps illustrate the focusing and de-focusing effects of structural features in prospect drainage areas (Fig. 10.34). When lateral migration is long distance, as for example in foreland basins, where prospects may be remote from areas of mature source rock (source kitchens), these effects may strongly influence the pattern of hydrocarbon charge. It is important in play assessment to recognize those parts of the fairway that are located on petroleum migration routes. A petroleum flow may be split when encountering a low, and concentrated along regional highs. The geometry of the kitchen also affects petroleum charge volumes; prospects located close to the ends of strongly elongate source kitchens will receive relatively little charge.

It is important that orthocontour maps are constructed for the actual time of secondary migration. Present-day structure maps may be used to model present-day migration. Isopaching (or 3-D decompaction, see §9.3) allows the production of paleostructure maps for use in modeling paleomigration routes. For example, an isopach of the base Upper Cretaceous to base Miocene interval will allow the modeling of migration routes in a carrier bed situated at the base of the Upper Cretaceous sequence at the beginning of Miocene time.

Other factors that should also be considered in evaluating migration pathways include the presence of sealing faults, which may deflect petroleum flow laterally, and nonsealing faults, which allow petroleum to flow across the fault plane into juxtaposed permeable units at a different stratigraphic level. From this point a different structure map needs to be used for migration modeling. Communication between carrier beds caused by lateral stratigraphic changes (e.g., by the sanding-out of a shale seal) also needs to be considered. The orthocontour map should be constructed only as far as a seal persists. These factors affect the likelihood of petroleum charge into specific segments of the play fairway, and into specific prospects within them.

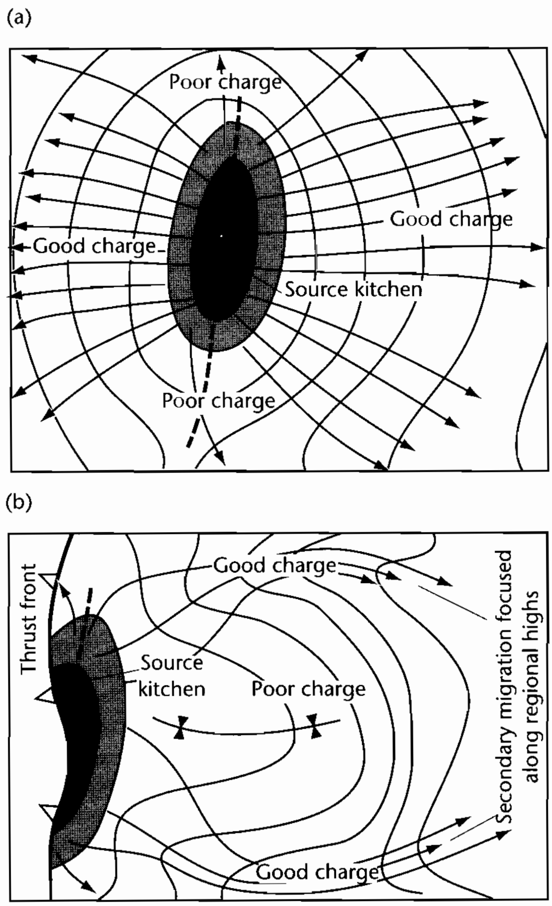


Fig. 10.34 Orthocontours illustrating secondary migration routes. (a) Effect of an elongate kitchen on migration directions. Areas along the long axis of the kitchen may receive a relatively poor charge; (b) Migration is focused along regional highs in the basin drainage area, and may penetrate large distances away from the source kitchens. Some foreland basins show examples of this type of migration.

Secondary migration losses

Volume losses occur along secondary migration pathways. These losses are in two distinct habitats:

- In miniature traps – dead-ends along the migration route – produced by faulted and dip-closed geometries, and by stratigraphic changes. The traps may be observable but of no commercial interest, or they may not be observable at all, for example, if they are below the resolution of the seismic tool;
- as a residual petroleum saturation in the pores of the carrier rock, trapped by capillary forces in dead-end pores and absorbed onto rock surfaces. This may represent up to 30% of the pore volume through which the petroleum migrates (and a greater percentage of the hydrocarbon saturation achieved during active migration), so major losses may occur in this way. Losses are minimized when petroleum flows through a relatively small volume of carrier rock. This is achieved in high permeability strata where migration is rapid and takes place without large petroleum columns building up.

The petroleum volumes expelled, lost and trapped can be related by

$$V_{\text{expelled}} = V_{\text{lost}} + V_{\text{trapped}} \tag{10.11}$$

The aim of play assessment and prospect evaluation is to estimate V_{trapped}. Volumes expelled can be calculated after geochemical source rock evaluation, taking into account source rock richnesses, thicknesses, source rock kitchen sizes and maturities, and expulsion efficiencies. However, at the basin or play scale, volumes lost are almost impossible to quantify. Moreover, they are likely to be very large in relation to volumes trapped. As a result, it is very difficult to estimate the volumes trapped in a play fairway through geochemical source rock volumetrics.

It is conceivable that a prospect may lie beyond the "migration front" of oil generated from a source kitchen. It will not receive a charge, since all of the oil expelled into the carrier bed is lost as a residual saturation (and in small traps) in the carrier bed. In order to determine the position of the migration front, accurate calculations of the volumes of petroleum expelled from the kitchen and the rate of loss in the carrier bed need to be made. The errors involved are huge and it would be most unwise for a prospect lying just beyond the calculated migration front to be severely downgraded for this reason. The calculations may, however, give useful order-of-magnitude estimates that assist risk estimation.

The focusing of oil migration into specific flow routes, which sweep through only a very small volume of carrier rock, is probably a very important contributing factor in enabling huge oil volumes to migrate very large distances (several hundred km) in some foreland basins. These have been previously described in §10.2.2 as petroleum systems with low-impedance entrapment style and a lateral migration style. The heavy oil/asphalt belts on the gentle flanks of these basins (e.g., western Canada) have formed at enormous distances from their source kitchens.

10.3.2.5 Alteration of petroleum

Trapped petroleum is not in equilibrium with its environment. Changes may take place in the physical and chemical properties of petroleum while it is in the trap. The longer that petroleum sits in the trap, the more likely it is that physical, chemical, and biological processes will significantly alter its original composition. These changes may have an important impact on the recoverable fraction and commercial value of an oil accumulation.

Source rock characteristics are the greatest influence on oil composition prior to trapping. Pressure-volume-temperature (PVT) conditions are the main influence on the original composition of reservoired oil. Secondary alteration processes are considered under the following four main headings.

1 Biodegradation

Biodegradation is the bacterial alteration of crude oils. Bacteria use any dissolved oxygen present in formation pore waters, or derive oxygen from sulfate ions, in order to selectively oxidize hydrocarbons. Firstly, the light normal-alkanes are removed, followed by branched (iso) alkanes, cycloalkanes, and finally the aromatics. The physical effect of biodegradation is to increase the density and viscosity of the oil.

Biodegradation appears to take place only at temperatures of less than 60–70 °C. It also appears to require a supply of meteoric water containing dissolved oxygen and nutrients (primarily nitrates and phosphates). These conditions are frequently met in foreland basins, where meteoric water enters the carrier bed/reservoir system in the bordering uplifted thrust belts. Biodegradation may take place in both the thrust belt and in the gentle foreland flank. An example of the former is the Napo Basin, Ecuador; the Athabaska Tar Sands of Canada are an example of the latter. Biodegradation may also occur at the oil–water contacts of petroleum accumulations, resulting in the formation of tar mats, as in the Burgan field of Kuwait.

2 Water washing

Water washing commonly accompanies biodegradation. Hydrocarbon-undersaturated meteoric waters may dissolve some hydrocarbons from a reservoired petroleum mixture. Light alkanes and low boiling point aromatics (e.g., benzene, toluene, and zylene) are the most soluble and preferentially removed. The net result is a change in composition similar to that caused by biodegradation. Water washing takes place at temperatures greater than 70 °C. The only requirement is a continued flow of meteoric water.

An example of the profound effects of water washing on petroleum volumes and composition is the northern Bonaparte Basin of Australia (Newell 1999). Long columns of residual oil occurring beneath many of the 11 discovered oil fields had been previously attributed to failure of fault seals. However, aspects of the geochemical composition of the very light oils found in this basin, most importantly the almost complete absence of the highly water-soluble light aromatics benzene and toluene, indicate alteration by water washing. Remarkably, in the order of 70% of the original oil volume in the reservoir has been lost by this process. Subsurface pressure data collected during exploration drilling operations indicate a water flow from the northwest, which can probably be explained by the dewatering of sediments overthrusted by a terrane forming the island of Timor during the last 7 Myr.

In assessing the chances of encountering biodegraded or water washed petroleum in a prospect or play, it is necessary to consider the history of fluid movement in the basin since the time of migration through to the present day. Although *present-day* reservoir temperatures may be >70 °C, this is not a guarantee that biodegradation has not taken place. The effects of strong convective meteoric water flow on geothermal gradients must also be taken into account when reconstructing the thermal history of the petroleum.

3 Deasphalting

Deasphalting is a process whereby the precipitation of the heavy asphaltene compounds in a crude oil takes place as a result of the injection of light C_1–C_6 hydrocarbons. This may occur when an oil accumulation experiences a later gas charge as its source kitchen becomes highly mature. It may also occur as a result of oil cracking in the reservoir rock. Deasphalting leads to the formation of light oil and a solid residue rich in asphaltenes. The tar mat in the Norwegian Oseberg field may have been produced by deasphalting processes (Dahl and Speers 1986).

4 Thermal alteration

The variations in petroleum composition that take place with increasing thermal maturity of the source rock were described in §10.3.2.2. Similar compositional changes take place in a reservoired petroleum with rising temperature. This normally occurs when trapped oil is heated through continued burial. Heavy compounds are replaced by progressively lighter ones, until only methane and a solid residue (pyrobitumen) is present. At high temperatures (>160°C), oil cracking reactions proceed so rapidly that an oil accumulation may be destroyed within a geologically short period of time.

In addition to the four processes described above, oil composition may also be altered as a result of *gravity segregation* and *dysmigration*. Gravity segregation may take place over long periods of time as heavier molecules sink under gravity toward the base of a hydrocarbon column. Leakage through a caprock (dysmigration) may result from faulting or micro-fracturing that alters the PVT conditions in the reservoir. A gas phase may form as a result of the pressure drop, and leak through the fractured caprock, leaving a heavier oil accumulation in place.

It is important when assessing exploration plays to block out parts of the fairway that are considered to be susceptible to the petroleum alteration processes described above.

10.4 THE RESERVOIR

Summary

A petroleum play is defined initially by the depositional or erosional limit of its gross reservoir unit. A reservoir rock must be porous enough to constitute a "tank" of petroleum within the trap, and its pores must be sufficiently interconnected to allow the contained petroleum fluids to flow through the rock towards the well-bore. Thus, the primary considerations in the assessment of reservoir potential are the likely reservoir *porosity* and *permeability*.

Reservoir porosity affects the reserves of a prospect or play. Reservoir permeability affects the rate at which petroleum fluids may be drawn off from the reservoir during production. Both of these parameters have a large impact on the commercial attractiveness of an exploration or field development opportunity. Reservoir rocks may result from deposition in a very wide range of environments. Particularly favorable reservoir rocks occur in specific depositional environments and in specific positions within the stratigraphic architecture. There is a strong depositional control on reservoir quality but also a very strong overprint from diagenetic changes.

The pore systems of carbonate rocks are complex, partly due to the varied biological origin of the carbonate grains, but also because their chemical reactivity makes them susceptible to major changes after deposition. Diagenetic changes, such as dolomitization, fracturing, dissolution and recrystallization and cementation are therefore a key element in the development of carbonate reservoirs. Diagenetic changes in the near-surface zone (eogenesis) can be related to depositional environment, climate, and relative sea level. Some of the most important carbonate reservoirs result from dolomitization of carbonate sediments from brines originating in evaporative marginal marine sabkhas and extensive shelf lagoons. Other carbonate reservoirs have been strongly influenced by meteoric waters flushing through the carbonate sediment at relative sea-level lowstands. Burial diagenesis (mesogenesis) of carbonate rocks is dominated by rock–water interaction and mixing with basin-derived fluids. Dedolomitization is a process causing an improvement in permeability that takes place during mesogenesis.

Sandstone reservoirs have a depositional porosity and permeability controlled by grain size, sorting, and packing of the particulate sediment. Diagenetic changes include the formation of clay minerals in the pore space. The formation of kaolinite, "green clay minerals" and smectites is extremely important in the eogenetic zone. As in carbonate reservoirs, the particular diagenetic products are related to depositional environment, climate and relative sea level. Subaerial exposure of the shelf at lowstands promotes kaolinite cementation, whereas transgression favors "green clay minerals" such as glauconite and berthierine formation. Burial diagenesis causes mineral transformations to dickite, illite, and chlorite as a function of temperature. Uplift and erosion (telogenesis) favors dissolution and kaolinite cementation.

Reservoirs are heterogeneous on a number of scales from the km-scale first-order heterogeneities of stratigraphic packages to the microscopic grain scale. Reservoir heterogeneity is the main concern of the development geologist, and constitutes essential input into numerical simulation models of the flow of fluids through the reservoir.

10.4.1 Porosity and permeability

The pore volume of a sediment can be expressed either as an absolute porosity ϕ_a given by

$$\phi_a = \left(\frac{V_b - V_s}{V_b}\right)100 \qquad (10.12)$$

where V_b and V_s are the bulk and solid volumes respectively, or, as an *effective porosity*

$$\phi_e = \left(\frac{V_i}{V_b}\right)100 \qquad (10.13)$$

where V_i is the interconnected pore volume. Effective porosity is normally measured in studies of reservoirs. Different rock types possess different pore geometries, carbonate rocks (§10.4.2) being very different to siliciclastic rocks (§10.4.3) in this respect. As described in §9.2.3, porosity can be estimated from a number of downhole wireline logs.

Permeability K or hydraulic conductivity measures the ability of a medium to transmit fluids and is defined according to the Darcy equation which states

$$Q = KA(\mathrm{d}P/\mathrm{d}l) \qquad (10.14)$$

where Q is the volume of transmitted flow per unit time (flow rate), A is the cross-sectional area and $\mathrm{d}P/\mathrm{d}l$ is the pressure gradient over distance l, or hydraulic gradient. The value of permeability depends not only on rock properties, but also on the medium being transmitted. The *specific permeability*, k, is defined as

$$Q = \frac{kA\gamma}{\mu}\left(\frac{\mathrm{d}P}{\mathrm{d}l}\right) \qquad (10.15)$$

where γ is the specific weight of the fluid and μ is its absolute viscosity.

Permeability can be measured by (i) well testing (measurement of the flow rate of a fluid to the well bore from the reservoir), which provides an average measurement of permeability across a certain reservoir interval, (ii) downhole wireline logs (reviewed by Ahmed et al. 1991), and (iii) core analysis (sidewall cores, core plugs, and whole core) which allows direct measurement of porosity and permeability under controlled laboratory conditions.

The porosity and permeability therefore describe the "plumbing" of the reservoir. Porosity and permeability are not, however, simply or directly related. Complex pore geometries may present highly tortuous paths for transmitted fluids with many dead-ends. This will lower permeability while porosity may be largely unaffected. Similarly, particular pore-filling mineral habits may have different effects on porosity and permeability.

10.4.2 Carbonate reservoirs

Carbonate rocks are particularly amenable to the study of the relationship between pore geometry and permeability (e.g., Jardine and Wilshart 1987). Carbonate reservoirs are characterized by extremely heterogeneous porosity and permeability on a number of scales. The main reasons for such heterogeneity are the biological origin of the carbonate grains and their strong chemical reactivity. The types of heterogeneity are therefore dependent on the original grain types and, most importantly, on the subsequent diagenetic alteration of the sedimentary fabric.

Carbonate porosity classification

A number of carbonate porosity classifications have been suggested (see Moore 2001 for review). Choquette and Pray (1970) presented a genetic classification that emphasized the importance of depositional and diagenetic fabrics in controlling pore systems (Fig. 10.35a). If porosity is determined by fabric elements, it is said to be *fabric-selective*. Five types of primary fabric-selective porosity were identified: interparticle, intraparticle, fenestral, shelter, and growth framework. Two types of secondary fabric-selective porosity, intercrystal and moldic, were also recognized. Some porosity types are not determined by the fabric of the sediment, such as fracture porosity, channel, vug, and cavern types. Other porosity types may be either fabric-selective or not, such as breccia, boring, burrow, and shrinkage types. Each of these porosity types may be associated with a particular depositional environment, diagenetic history, and position within a cycle of relative sea-level change.

Lucia (1983, 1995, 1999) placed emphasis on the petrophysical aspects of carbonate pore systems, suggesting that there are two major types of carbonate porosity. The pore space between grains is termed interparticle pore space and all other pore space is termed vuggy, subdivided into separate vugs connected only through the

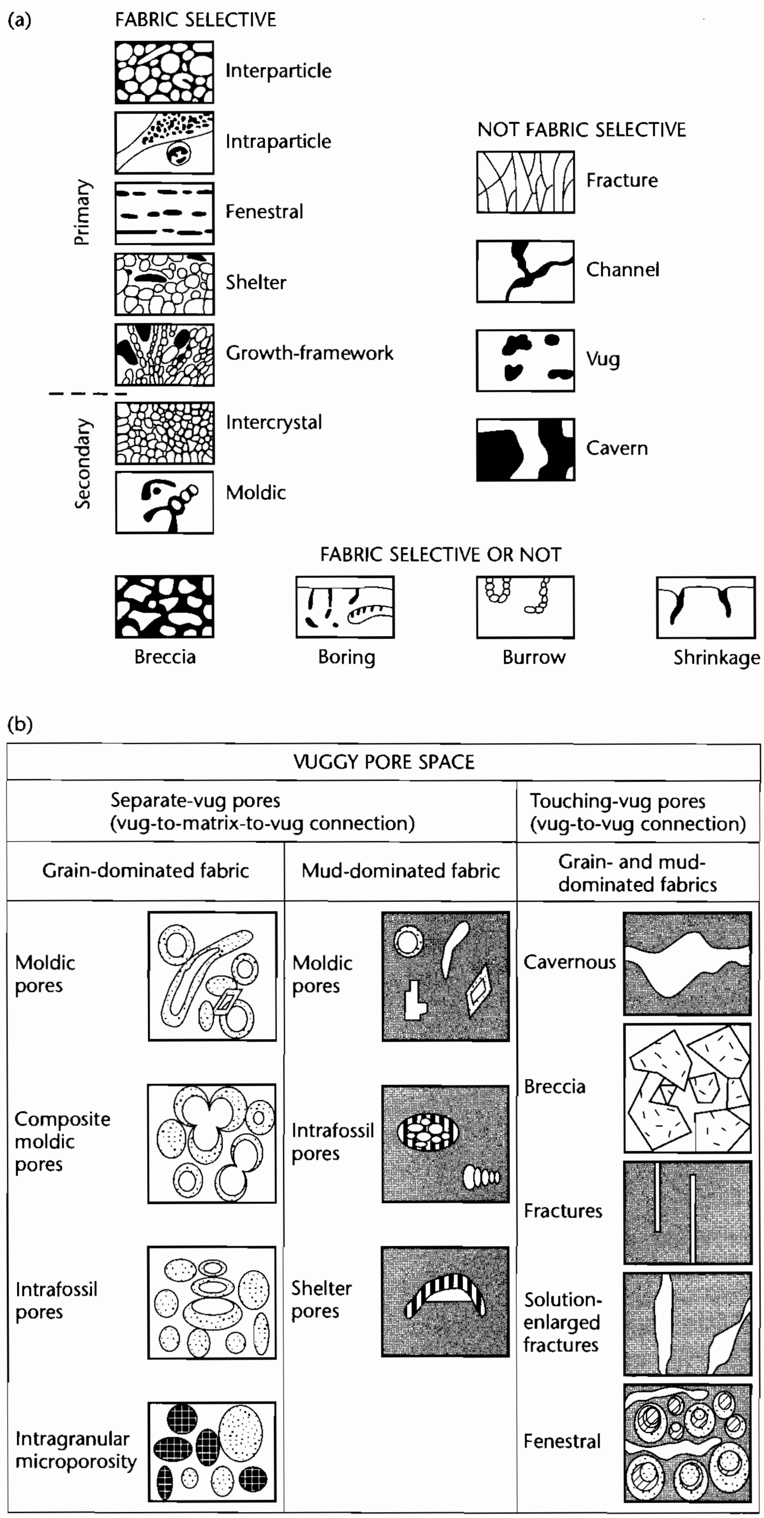


Fig. 10.35 Classification of carbonate porosity: (a) based on the fabric-selective and the non fabric-selective criteria of Choquette and Pray (1970), (b) based on the petrophysical classification of vuggy pore space and vug interconnection of Lucia (1995). Reproduced courtesy of American Association of Petroleum Geologists.

interparticle pore network, and touching vugs that form part of an interconnected pore system (Fig. 10.35b). These three types have different porosity–permeability characteristics and are therefore distinct petrophysically.

Diagenesis of carbonates

Although depositional environment and grain types are important in determining the primary porosity of a carbonate sediment, the postdepositional evolution of porosity is often the key element in the formation of carbonate reservoirs. Dissolution during burial of a carbonate sediment dominates the formation of secondary porosity. Initially, secondary porosity is fabric-selective in the so-called *eogenetic* zone. Later during burial, in the *mesogenetic* (beyond the influence of surficial processes) and *telogenetic* (exhumation back to the region of surficial processes) zones, porosity generation is generally not fabric-selective. One of the most important processes during diagenesis of carbonate rocks is *dolomitization*. Dolomitization may result in cementation because of a net import of CO_3 (Lucia and Major 1994), or if CO_3 is locally sourced, may result in net production of porosity (Moore 1989; Purser et al. 1994). Dissolution by ingress of fresh meteoric water during periods of exposure is perhaps the most important process enhancing porosity during dolomitization.

Secondary porosity associated with breccias can result from evaporite solution collapse, limestone solution collapse, faulting, and soil formation (Blount and Moore 1969). For example, solution collapse breccias produced during periods of influx of fresh meteoric waters at times of subaerial emergence contribute significantly to the porosity of the Ordovician Ellenburger carbonate reservoir in Puckett field, west Texas (Loucks and Anderson 1985). Major karstic dissolution associated with major unconformities is responsible for a number of important carbonate reservoirs, such as the Mississippian Northwest Lisbon field, Utah (Miller 1985) and the Permian Yates field, west Texas (Craig 1988). Intense fracturing commonly enhances porosity in carbonate rocks. A good example is the Oligocene Asmari Limestone of Iran. Despite a matrix porosity of just 9%, the reservoir produces up to 80,000 barrels of oil per day from a fractured reservoir (McQuillan 1985).

Eogenesis and relative sea-level change

The methodology of process stratigraphy (§8.1–§8.2) facilitates an explanatory approach to the occurrence of carbonate reservoirs. A number of common stratigraphic contexts (Fig. 10.36) can be linked to the occurrence of productive carbonate reservoirs (Saller et al. 1994; Harris et al. 1999; Moore 2001):

Sea-level lowstand (lowstand systems tract, LST)

On carbonate ramps and rimmed carbonate shelves, lowstands of sea level are important because in humid climates chemically unstable marine sediments are potentially subjected to flushing by large volumes of undersaturated meteoric waters. This modifies the porosity and permeability of the host sediment. Marine carbonate sediments commonly are exposed and develop *karst systems* that enhance vertical conductivity of fluids. Gravity-driven meteoric water may move towards the coastline, mixing with marine water, and causing dissolution, secondary porosity, and some dolomitization. On isolated carbonate platforms (such as atolls), there is no active gravity-driven flow beneath the platform, leaving a platform-wide meteoric lens floating on marine water at a sea-level lowstand. Cementation may take place along the water table, negatively impacting porosity, but cavernous, karstic porosity may develop along the periphery of the platform. The core of the platform is pervasively dolomitized in a mixing zone between the meteoric lens and marine water drawn into the platform.

Sea-level rise (transgressive systems tract, TST)

Diagenesis during sea-level rise is dominated by marine water. During sea-level rise on a ramp, deposition of transgressive deposits seals a confined, gravity-driven flow in the highstand deposits of the underlying depositional sequence, often associated with porosity gain in the up-dip recharge area, and porosity loss by cementation in the down-flow area. On rimmed carbonate shelves, reef growth typifies the shelf margin during relative sea-level rise, giving good framework porosity, but marine cementation may reduce porosity along the shelf margin. The interiors of isolated carbonate platforms are generally open to marine waters during a sea-level rise and there is little meteoric water influence. Reefs may track sea-level rise, particularly on the windward side. Minor dolomitization of platform margins by marine waters driven by thermal convection, or reflux from the interior of the platform during arid periods, results in porosity loss by cementation.

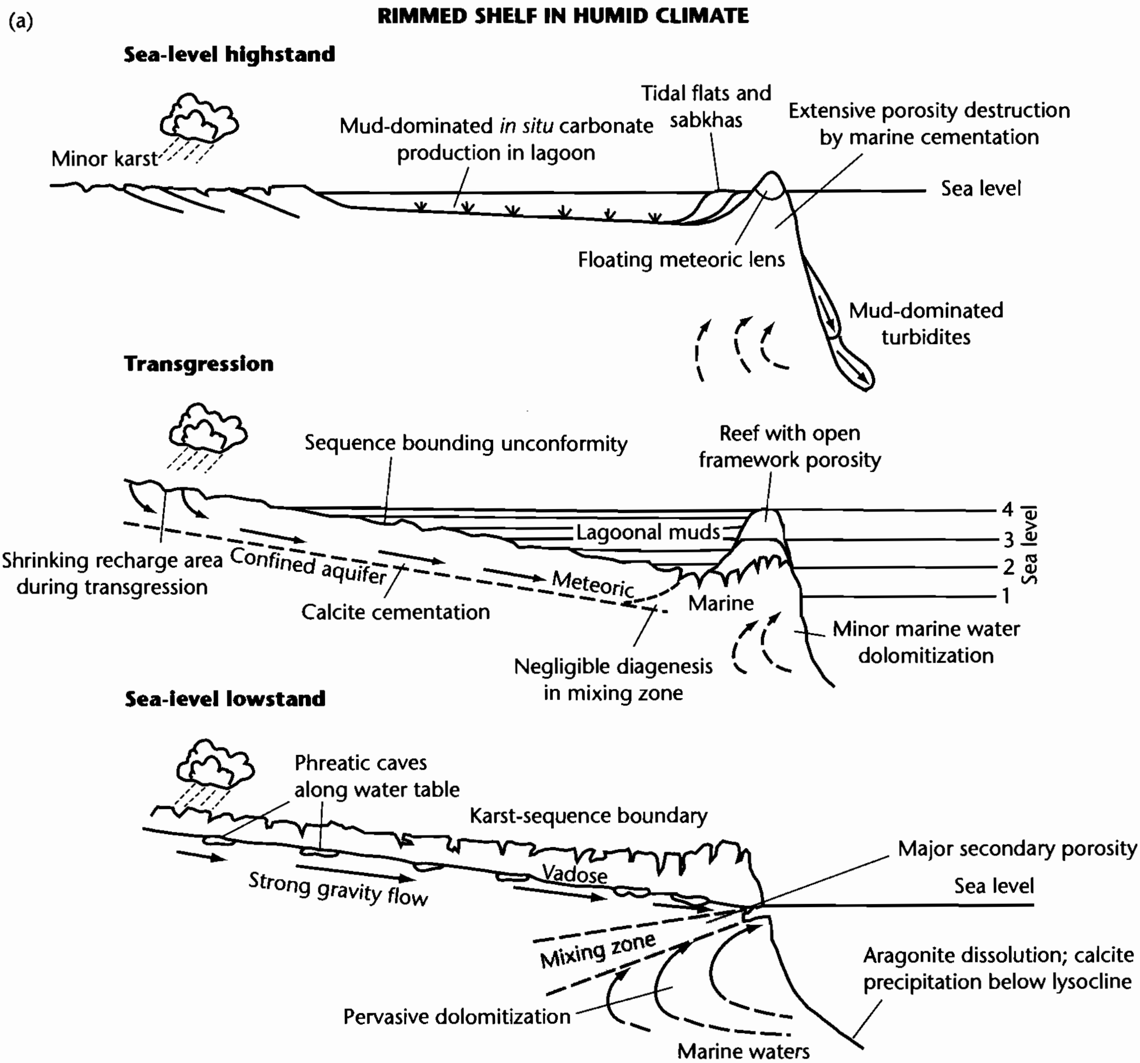


Fig. 10.36 Effects of relative sea level, depositional environment, and climate on the eogenetic changes in carbonate sediments, using a rimmed shelf system as an example (after Moore 2001). (a) Eogenetic processes during relative sea-level lowstand, transgression and highstand for a rimmed shelf in a humid climate; (b) The equivalent processes in an arid climate.

Sea-level highstand (highstand systems tract, HST)

Ramps strongly prograde and shelf and platform margins slowly accrete during the late highstand as accommodation generation reduces. At a time close to the maximum flooding, the slope and basin offshore ramps receive minimal sediment input, allowing deep-water microbial *mud mounds* to form. The progradational carbonate shoreline of the ramp contains freshwater lenses during humid periods, but during arid intervals, short-lived meteoric lenses are isolated by saline ponds. Heavy brines reflux downwards through underlying coastal zone sediments causing significant

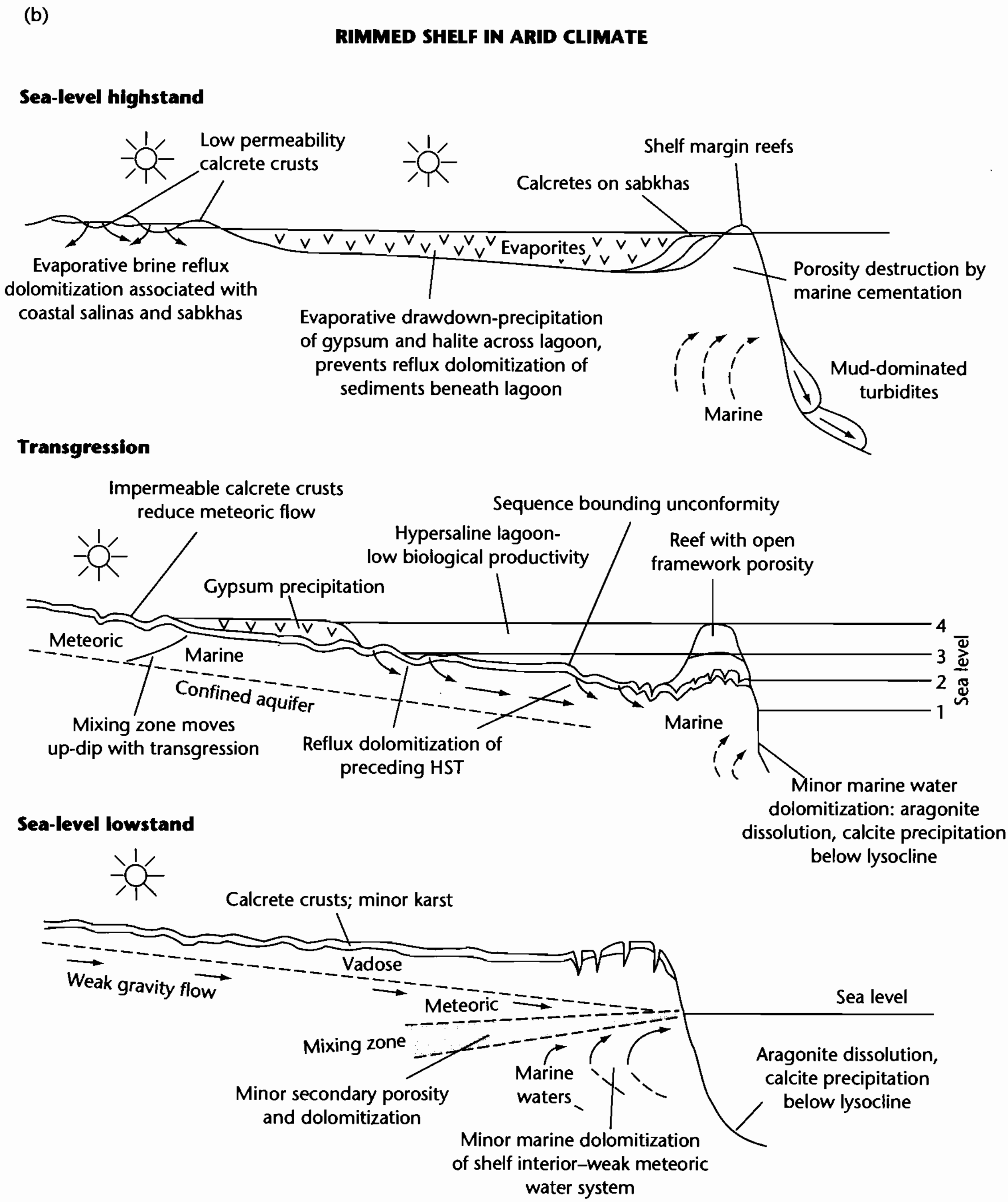


Fig. 10.36 *Continued*

dolomitization. If evaporites are precipitated in the salinas above, the brines are deficient in the Ca and CO_3 necessary for dolomitization, so the underlying carbonates are dissolved during dolomitization, which enhances secondary porosity. On rimmed shelves and isolated platforms, reefs easily keep up with sea level and shelter mud-dominated aggradational and progradational coastal tidal flats, while turbidites are shed into deep water. Reef bodies, if leached by meteoric water, or dolomitized in a marine–meteoric mixing zone, may have good reservoir properties, but otherwise, may suffer extensive porosity-reducing marine cementation.

The depositional and diagenetic histories of individual carbonate reservoirs are therefore complex and unique. Some of the most important carbonate reservoirs result from dolomitization from brines originating in evaporative marginal marine sabkhas and shelf lagoons. The Permian Capitan reef complex of the Guadalupe Mountains of west Texas and New Mexico evolved from a progradational build-up on a ramp to a steep fronted shelf margin reef and eventually into patch reefs (Kirkland et al. 1998). The reef carbonates have a good primary framework porosity. The shelf margin carbonates of the Capitan pass laterally into extensive Upper Permian shelfal carbonates and evaporites of the Artesia Group, representing deposition in a large evaporative shelf lagoon (Sarg 1981). Dense brines moved from this evaporative lagoon and dolomitized associated carbonate facies, to produce the most prolific oil-producing reservoirs in west Texas (Silver and Todd 1969). The Upper Jurassic Smackover Formation of east Texas, which accumulated as ooidal grainstones on high energy platforms in a late highstand systems tract, has been extensively dolomitized by reflux from overlying evaporites deposited during a lowstand in the overlying depositional sequence (Moore and Heydari 1993). One of the most prolific hydrocarbon systems in the world is found in the Upper Jurassic of the Persian Gulf and Saudi Arabia (Droste 1990) (Fig. 10.37). The Arab Formation carbonates and Hith anhydrite form part of a highstand systems tract. The dolomitization of Arab D reservoirs, including the world's largest field at Ghawar, is due to refluxing brines from the overlying Arab D evaporative lagoon, as in the case of the Smackover Formation.

Flushing with freshwater has also been identified as an important factor in the development of carbonate reservoirs (Fig. 10.36). The Pennsylvanian carbonate reservoirs of the Aneth Field of the Paradox basin, USA (Grammer et al. 1996) are carbonate mud mounds that have experienced secondary meteoric dissolution during

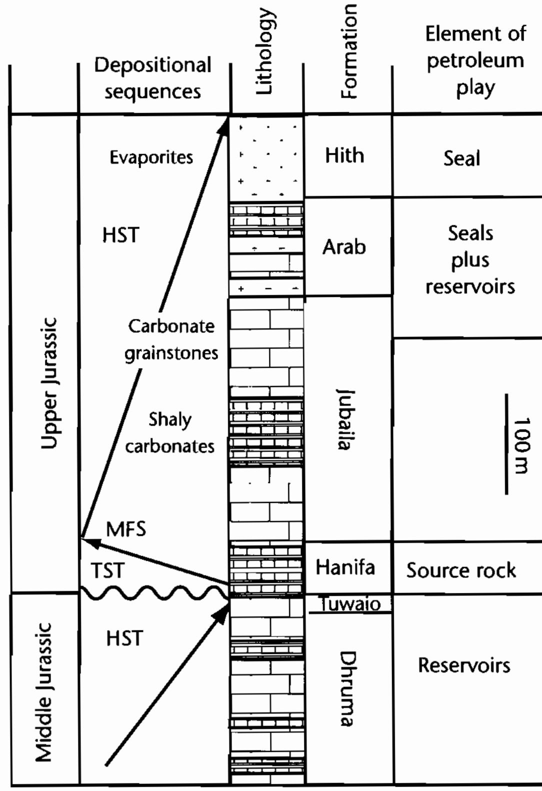


Fig. 10.37 Stratigraphic column of the Middle and Upper Jurassic of Saudi and the Persian Gulf, modified after Droste (1990). The Hith Formation constitutes an excellent regional topseal. Arab carbonate reservoirs are sealed by Arab evaporitic beds. The Hanifa Formation is an important source rock. Reproduced courtesy of Elsevier.

sea-level lowstands. The Ordovician Red River reservoirs of the Williston Basin, USA–Canada (Ruzyla and Friedman 1985) are dolomitized sabkha carbonates associated with evaporites, but secondary porosity is strongly influenced by freshwater flushing. The Ordovician Ellenburger Formation of west Texas consists of shallow marine shelf to marginal marine supratidal–intertidal deposits that have experienced freshwater flushing during lowstands. The Puckett Field has produced >2.6 tcf gas from dolomites produced by reflux of evaporative brines from adjacent sabkhas (Loucks and Anderson 1985), but secondary porosity has been strongly enhanced by solution collapse breccias related to subaerial exposure. Freshwater flushing of a prograding highstand shoreline succession has been invoked to explain diagenesis in the

Jurassic Oaks Field, Louisiana (Moore and Heydari 1993).

Burial diagenesis

The depositional fabrics and early diagenetic changes outlined above are invariably part of an evolutionary pathway leading to deep burial diagenesis or mesogenesis (Fig. 10.38). In the burial environment, sediments are beyond the reach of surface-related processes. Pressures and temperatures increase, and fluids are cut off from free exchange with the atmosphere. Chemical changes are therefore dominated by rock–water interaction and mixing with basin-derived fluids. The hydrology of deep basins depends on their large-scale tectonics (Fig. 10.39). For example, passive margin wedges (e.g., Northern Gulf of Mexico) have a high velocity, near surface, gravity-driven flow towards the distal basin, and a deep, moderate velocity, compaction-driven flow moving from deep

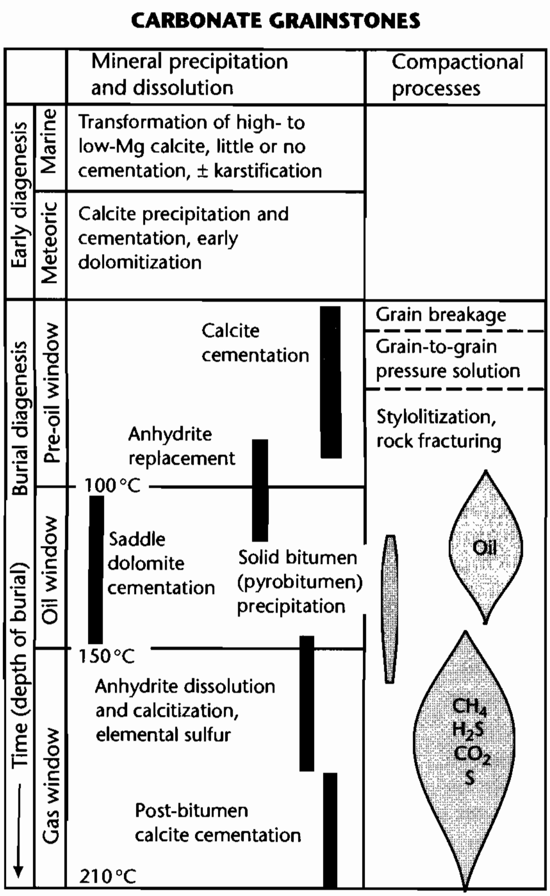


Fig. 10.38 Relationship between early (eogenesis) and deep burial diagenesis of carbonate grainstones, and the maturation of organic matter. After Heydari (1997). Reproduced courtesy of Springer.

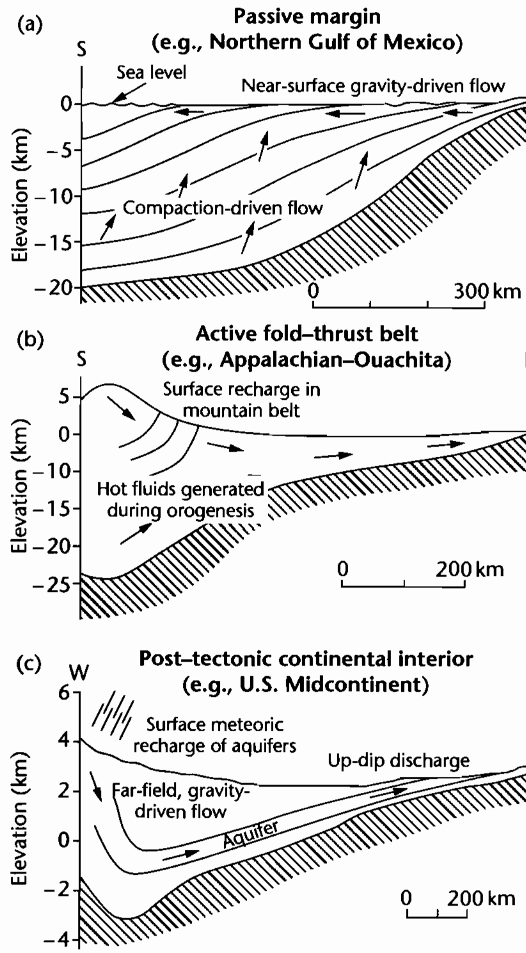


Fig. 10.39 Models of basin-scale fluid movement (after Moore 2001). (a) Passive margin, with near-surface gravity-driven flow and slow upward movement driven by compaction of the deep sedimentary column; (b) Active fold–thrust belt causes the up-dip migration of hot fluids; (c) Post-tectonic environment, characterized by long distance fluid transport in regional aquifers, driven by gravity acting on recharged water in the upland. Reproduced courtesy of Elsevier.

to shallow levels (Harrison and Summa 1991). Mechanical and chemical compaction dominate porosity changes, and cementation is relatively unimportant. The major source of $CaCO_3$ for cementation is pressure solution, but the volumes involved are limited. Other sources are dissolution caused by the action of aggressive pore fluids produced during organic diagenesis. Active fold–thrust belt and foreland basin settings (e.g., Lower Paleozoic Ouachita–Appalachians) have focused hot fluid flows caused by tectonic loading. The hot fluids react strongly with the rocks forming conduits for migration, causing recrystallization of early-formed calcite and dolomite, replacement dolomitization, dissolution of evaporites and precipitation up-dip. The Upper Knox Group carbonates (Lower Ordovician) of the southern Appalachians, USA have been strongly affected by a regional burial replacement dolomitization (Montanez 1994). In less active settings (Rocky Mountains of western USA–Canada), meteoritic waters recharge aquifers exposed in the mountain belt, setting up a far-field gravity-driven flow into the basin. Such meteoric recharge has negligible effects on carbonate porosity unless evaporites are dissolved. If so, the dissolution of gypsum promotes the dissolution of dolomite and precipitation of calcite (*dedolomitization*), thereby enhancing porosity. The Mississippian Madison aquifer of the mid-continent, USA (§9.6.3) is thought to show this down-flow path trend of dolomite dissolution and calcite precipitation (Plummer et al. 1990). The Madison is the reservoir for a number of fields, including the giant (>1 tcf gas), super-deep (23,000 ft, 7000 m) gas field at Madden Field, Wind River Basin, Wyoming, USA.

10.4.3 Sandstone reservoirs

Porosity and permeability of sandstone reservoirs

The primary porosity and permeability of sandstones are dependent on the grain size, sorting, and packing of the particulate sediment (see summary in Pettijohn 1975, pp. 72–79) and are therefore easier to predict than in carbonate reservoirs. The porosity of artificially packed natural sand is independent of grain size for sand of the same sorting, but porosity varies strongly with sorting. Average wet-packed porosity for a range of sorting groups varies between 28% for very poorly sorted sand to over 42% for extremely well-sorted sand.

In siliciclastic rocks, permeability is related to the pore throat size and the number of interconnected pores. However, the geological factors controlling these parameters may be complex. In unconsolidated sands, the most important factors are grain size and sorting. Sands with coarser grains have large pore throats and therefore a higher permeability. Consequently, permeability may vary over several orders of magnitude between very fine and coarse sand. For example, Hogg et al. (1996) measured permeability and porosity on samples obtained while drilling from the Triassic Sherwood Sandstone of Wytch Farm field, Dorset, UK (Fig. 10.40). The intercept of the regression on the permeability axis, representing the notional permeability at a zero porosity ranges from *c.* 0.001 mD for very fine grained sandstones to >1 mD for coarse grained sandstones.

Sands with poorer sorting have smaller mean pore throat diameters and therefore lower permeability than better sorted sediments with the same mean grain size. For wet-packed samples, permeability varies over more than an order of magnitude between extremely well sorted sands and very poorly sorted sands. The dual effects of sorting (expressed as standard deviation of grain size) and grain size (expressed as mean) on permeability is shown in Figure 10.41. The probable effect of low sphericity (grain shape) and high angularity (grain roundness) is to increase porosity and permeability of unconsolidated sand.

Apart from textural properties of the sand, the presence of ductile clay intraclasts (Gluyas and Cade 1997), which may compact to form pseudomatrix, and infiltrated clays both serve to reduce porosity and permeability. Further porosity and permability losses occur during burial, when compaction reduces pore throat size and eventually blocks them completely. Although the evolution of porosity with depth in sedimentary rocks of different lithology is beginning to be understood (§9.2), the impact on permeability is less well known (see Ethier and King 1991). Different clay mineral cements can have different effects on permeability because they occupy different positions in the pore space (e.g., Howard 1992). Tangential grain coatings have a much smaller effect on permeability than clays growing perpendicularly to grain surfaces or lying within pore throats (Pallatt et al. 1984; Kantorowicz 1990). Discrete aggregates, though reducing porosity, may have little effect on permeability, unless they occur as a pseudomatrix, which on compaction severely reduces porosity and permeability.

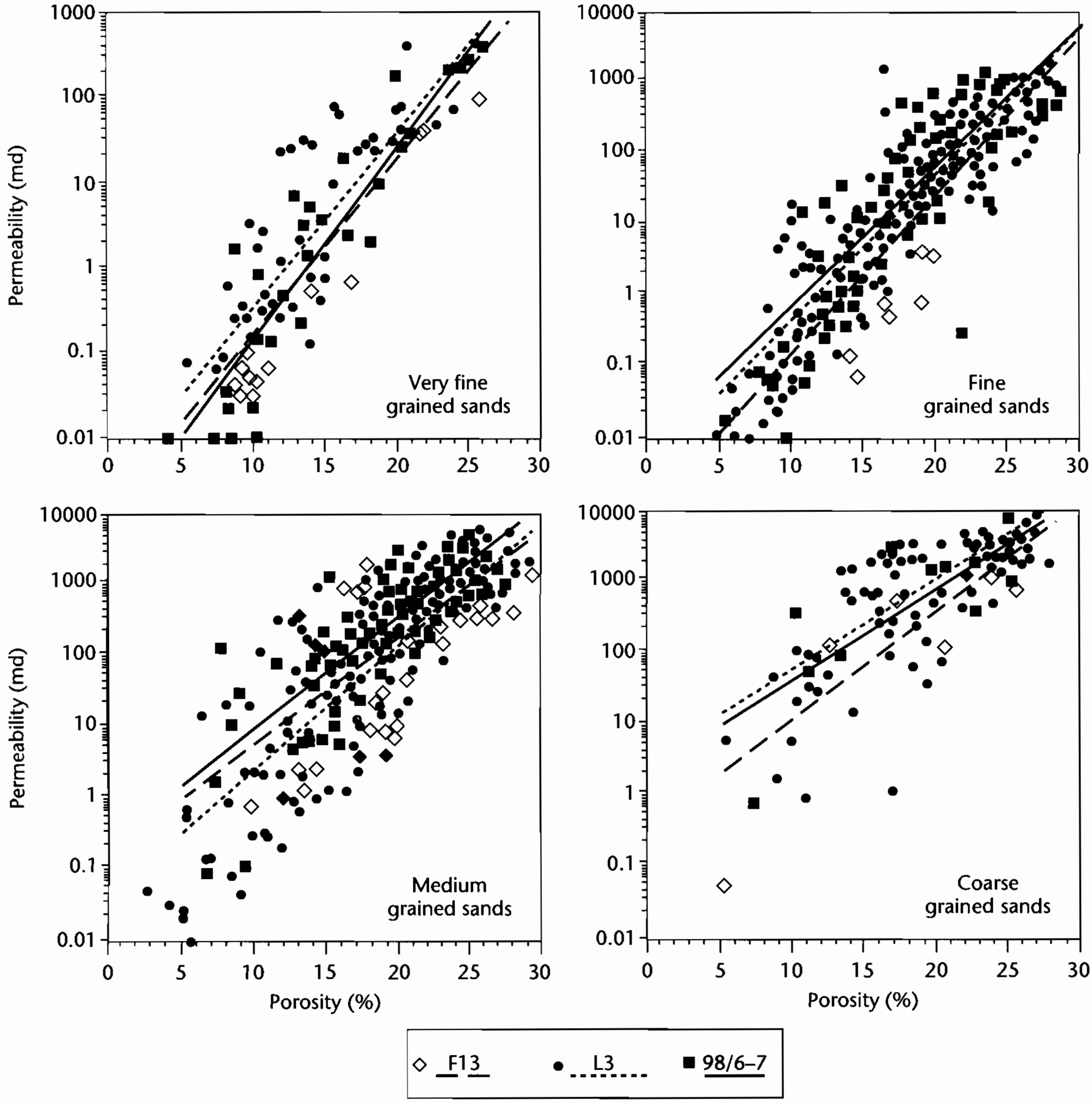


Fig. 10.40 Relationship of permeability with horizontal core plug porosity for four grain size classes in the Triassic Sherwood Sandstone reservoir in three wells in the Wytch Farm field, Dorset, UK. After Hogg et al. (1996). Reproduced courtesy of Geological Society of London.

Porosity and permeability can also be affected positively by early clay mineral growth. For example, chlorite rims on grains can inhibit later quartz cementation and pressure dissolution. Early introduction of oil into pore space stops or slows clay diagenesis in sandstones, thereby improving porosity and permeability relative to sandstones receiving a late hydrocarbon charge.

The major factors controlling permeability in sandstones are therefore grain size, sorting, percentage of

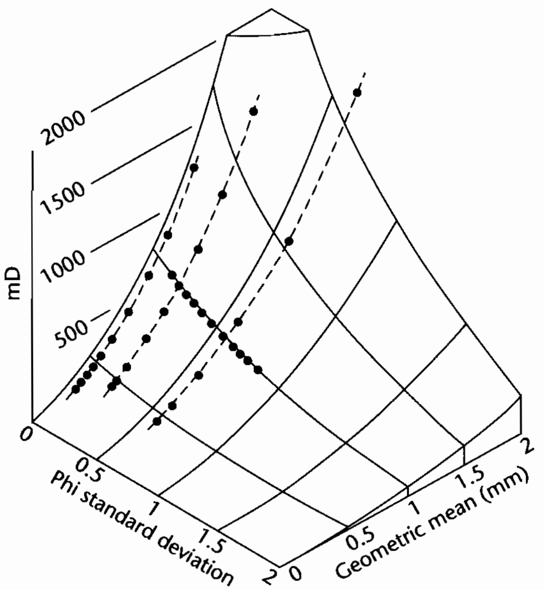


Fig. 10.41 Relation of permeability to grain size and sorting (after Krumbein and Monk 1942). The vertical axis is the permeability in milliDarcys. The grid lines on the "permeability surface" are parabolas parallel to the Darcy-size plane, and negative exponentials parallel to the Darcy-standard deviation plane.

ductile clasts, early clay infiltration, compaction, and cementation (Cade et al. 1994).

Clay mineral diagenesis, depositional environment, and relative sea-level change

There is now an impressive literature on the formation of clay minerals in sandstones during burial (Haszeldine et al. 2000; Morad et al. 2000; Ketzer et al. 2003; Worden and Morad 2003). The distribution of clay minerals formed in the *eogenetic* regime (<70 °C, <2 km burial) is closely related to depositional facies, climate, and stratigraphic surfaces (Fig. 10.42). Consequently, knowledge of the stratigraphic architecture of a basin is valuable for prediction of diagenetic trends and therefore sandstone reservoir quality.

The main eogenetic clay minerals can be grouped under the following headings: (i) kaolinite, (i) green clay minerals (glauconite, berthierines, verdine), and (iii) smectite, mixed layer illite/smectite, mixed layer chlorite/smectite and Mg-clay minerals (e.g., palygorskite). The formation of diagenetic clay minerals in near-surface sandstones and during shallow burial is controlled by depositional environment, detrital composition, and climatic conditions:

- Eogenetic *kaolinite* has a vermicular and book-like habit and forms under humid climatic conditions in continental sediments (Emery et al. 1990). It commonly forms during relative sea-level lowstand and relative sea-level fall (forced regression), when large areas of marine sediment are subaerially exposed and subjected to flushing by meteoric water. High rates of flushing are promoted by humid climatic conditions and high permeabilities, as in channel or shoreface sands;
- *green clay minerals*: berthierine and verdine occur as small (<5 μm) lath-shaped grain coatings and crystals, as coats, pellets, ooids, and void-fillings, or as replacements of detrital grains, commonly below the sediment–water interface in deltaic–estuarine deposits, primarily in tropical to subtropical seas. Berthierine is favored under reducing conditions in volcanogenic sediments in estuarine–coastal plain environments (Jeans et al. 2000), whereas verdine forms in mildly reducing conditions in continental shelf sediment off river deltas (<200 m water depths) under low sedimentation rates (Kronen and Glenn 2000). Glauconite forms exclusively in open marine sediments (Odin and Matter 1981) decimeters to meters below the seabed;
- *smectite* and mixed layer illite/smectite forms as grain-hugging flakes in semi-arid climates, whereas Mg-smectites and palygorskite form fibers or fiber bundles during near-surface diagenesis of lacustrine, fluvial, and eolian sediments under evaporative conditions. These minerals therefore commonly form eodiagenetically in arid continental environments.

Ketzer et al. (2003) and Worden and Morad (2003) provide summaries of the association of eogenetic clay minerals and systems tracts (Fig. 10.43). These associations can be summarized as:

1 Lowstand systems tract (LST): sediments on the subaerially exposed continental shelf are subjected to kaolinite eogenesis under humid climatic conditions and formation of Mg-rich clay minerals such as palygorskite under evaporitic arid conditions. Paleosols may form on interfluves between the main incised channels.
2 Transgressive systems tract (TST): berthierine may form in the upper part of incised valley fills at they are flooded during transgression. The transgressive surface may be lined with high amounts of glauconite

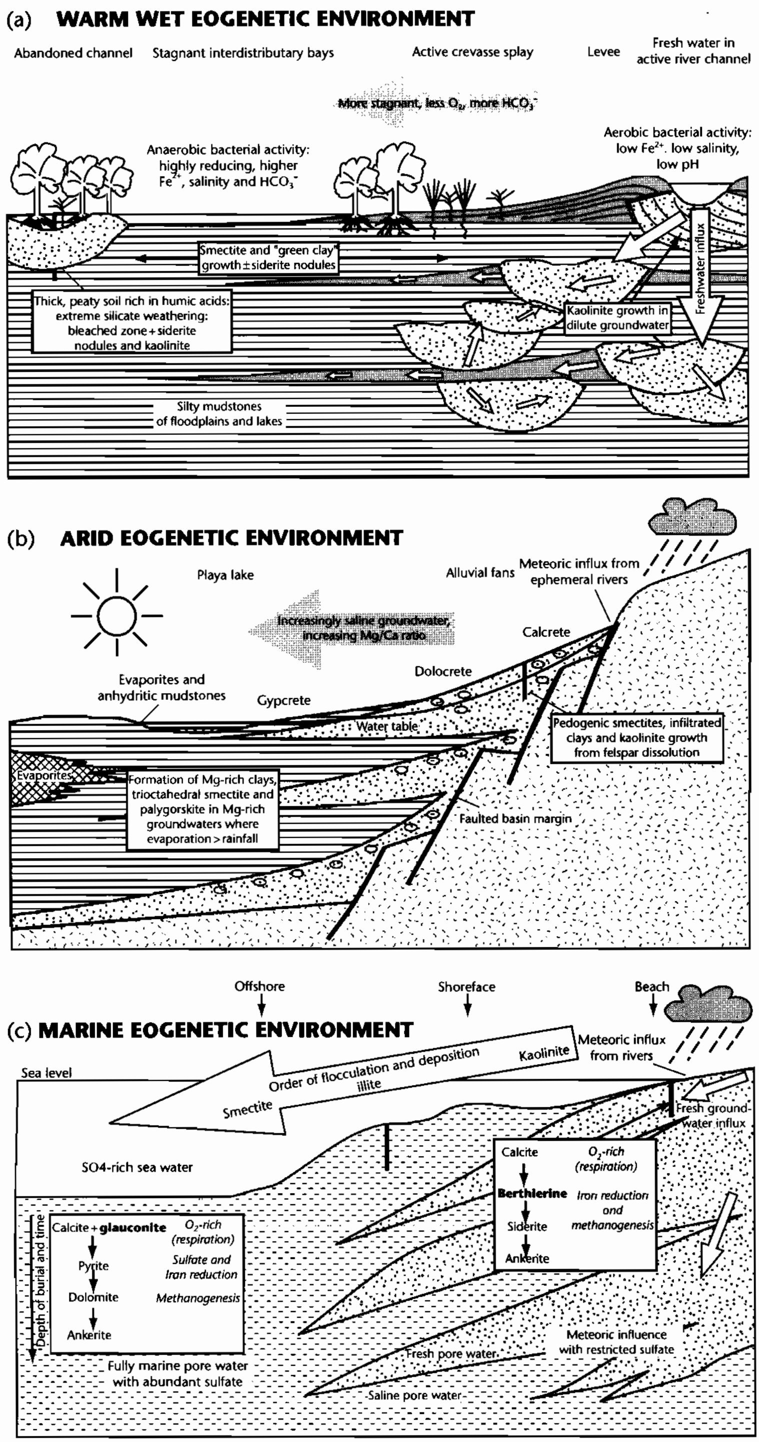


Fig. 10.42 Relation of clay mineral formation to depositional environment. (a) Warm, wet eogenetic environment of river channels, crevasse splays, and interdistributary bays; (b) Arid eogenetic environment of basin margin fans and evaporitic playas; (c) Marine eogenetic environment offshore from river entry points. For more details see Worden and Morad (2003). Reproduced courtesy of Blackwell Publishing Ltd.

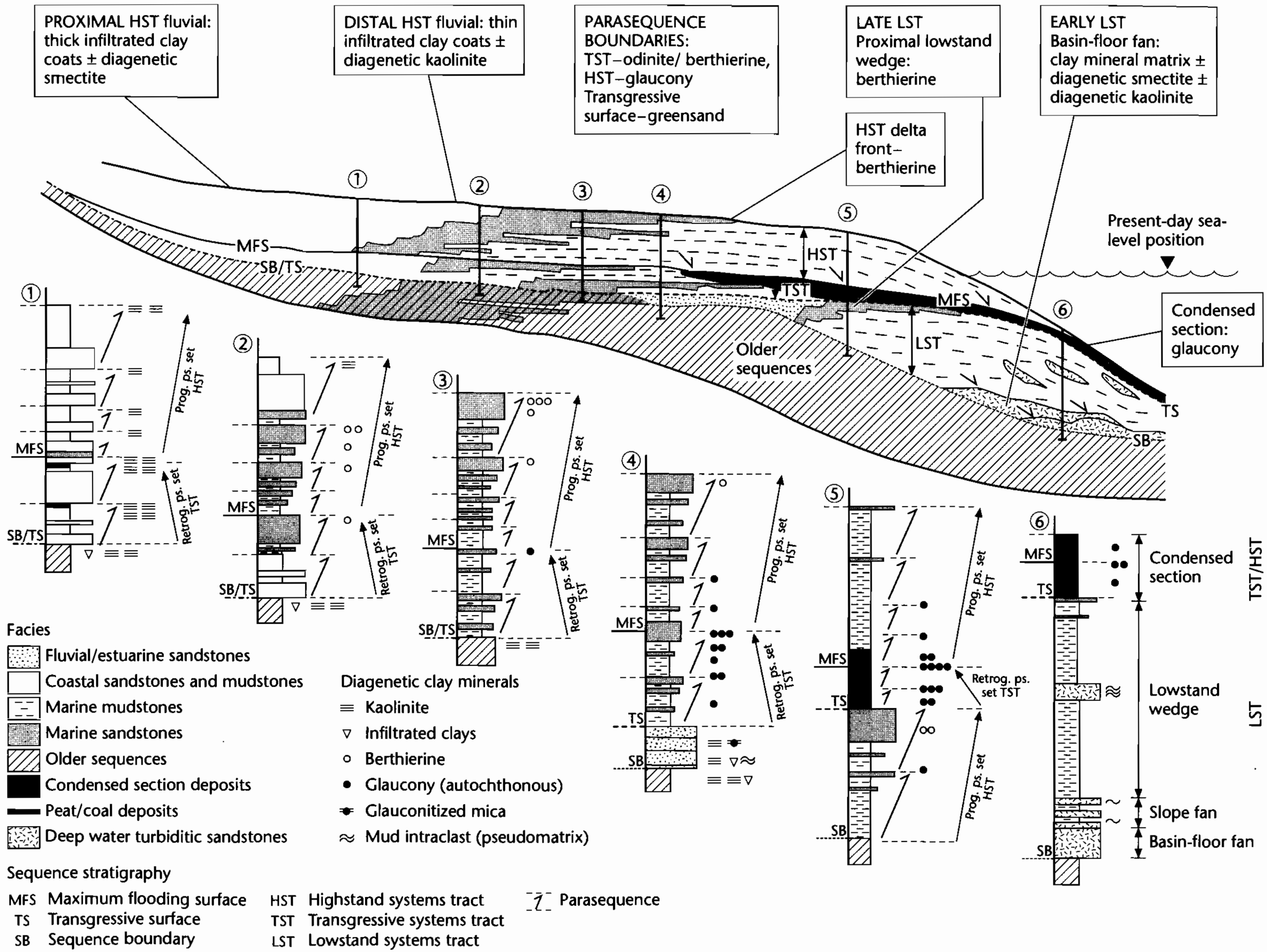


Fig. 10.43 Distribution of diagenetic clay minerals within a depositional sequence, modified after Ketzer et al. (2003). Sequence architecture from Van Wagoner et al. (1990). Diagenetic clay mineral types are shown in their typical positions within successions 1 to 6. Reproduced courtesy of Blackwell Publishing Ltd.

and verdine intraclasts, giving "greensands" overlying coastal plain sediments. As water depths deepen and the shelf becomes starved of coarse sediment, authigenic glauconite and verdine forms, with maximum concentrations along the maximum flooding surface, while berthierine forms in estuarine and shallow marine environments in front of deltas.

3 Highstand systems tract (HST): as highstand progradation takes place, the amounts of glauconite and verdine decreases and authigenic berthierine increases. The landward end of the HST may be composed of fluviatile sandstones subjected to kaolinitization under humid conditions, pedogenesis, or the formation of Mg-rich clay minerals in arid conditions.

MESOGENESIS AND TELOGENESIS OF SANDSTONES

In the burial diagenesis (mesogenesis) zone, temperature is the most important control on the formation of clay minerals. Eogenetic kaolinite, berthierine, and smectite are replaced by mesogenetic dickite, illite, and chlorite. Vermicular (worm-like) and book-like stacks of kaolinite crystals are progressively replaced by dickite above 70–90 °C (2–3 km burial depth), with a loss of the typical eogenetic kaolinite stacking pattern with increasing temperature and transformation to dickite (Beaufort et al. 1998). Transformation is aided by high permeabilities, so cannot be used as a simple paleothermometer. With burial and heating smectites pass progressively through interlayered forms to illite. Kaolinite also transforms to illite at temperatures above 70 °C, but especially above 130 °C. K-felspar and kaolinite react to produce illite and quartz, the quartz byproduct commonly forming discrete crystals or overgrowths. Dickite also transforms to illite at high temperatures. Finally, mesogenesis is typified by chloritization. Chlorite grain replacements may form as a result of breakdown of volcaniclastic grains, by transformation of smectite, or by alteration of previous "green mineral" grain coatings. Chloritization of kalonite can also occur at burial depths of 3500–4500 m (165–200 °C) (Boles and Franks 1979).

Burial diagenetic changes are well illustrated by the intensively studied Jurassic sandstone reservoirs of the Brent Group, North Sea. Reservoirs that have experienced only shallow burial have partially dissolved felspars and authigenic kaolinite. Deeper (>4 km) Brent reservoirs, however, have extensive illite, quartz, and ferroan carbonate cements, severely impairing reservoir quality (Bjorlykke et al. 1992; Giles et al. 1992). Felspars are essentially absent in these deep reservoirs (Glasmann 1992).

Based on a wide survey of diagenetic histories of sandstones (Primmer et al. 1997), there appear to be five distinct diagenetic styles that are related to original depositional environment, detrital composition and burial history:

- *Quartz*, commonly with smaller quantities of neoformed clays (kaolinite and/or illite) and late-diagenetic ferroan carbonate. This is the most common diagenetic style and is most likely to occur in mineralogically mature sandstones, deposited in high energy eolian, deltaic, and shallow marine environments. Quartz cements are temperature dependent and occur in large volumes at temperatures >75 °C;
- *clay minerals* (illite or kaolinite) with smaller quantities of quartz or zeolite and late-diagenetic carbonate. Illite rarely forms below 100 °C (Robinson et al. 1993). Kaolinite is very common and occurs in more mineralogically mature sandstones. Chlorite is very common in immature sandstones, and smectite only occurs in immature sandstones, such as deep marine deposits;
- *early diagenetic (low temperature) grain coating clay mineral cements* such as chlorite, which may inhibit quartz cementation during later burial;
- *early diagenetic carbonate or evaporite cement*, often localized, which severely reduces porosity at very shallow burial depths. Siderite is a common early carbonate cement in mature sandstones, typically fluviatile and shallow marine, whereas late diagenetic ferroan dolomite and calcite cements are most common in mineralogically immature sandstones;
- *zeolites*, which occur over a wide range of burial temperature, in association with abundant clay minerals (usually smectite or chlorite) and late diagenetic non-ferroan carbonates. This style is also likely to occur in mineralogically immature sandstones. Zeolites are common in deep marine sandstones and especially sandstones derived from volcanogenic terrains.

Telogenetic changes related to uplift and erosion leave a distinctive fingerprint on sandstone reservoirs. Meteoric water fluxes, especially along basin margins and uplifted fault blocks, are commonly dilute, oxidizing, saturated with CO_2 and therefore acidic. Felspars rapidly alter to clay minerals, reduced iron-bearing cements are oxidized, and calcite, dolomite, and sulfate cements are dissolved. The occurrence of kaolinite in the Jurassic Brent Group reservoirs of the North Sea is thought to be due to telogenesis.

HETEROGENEITY OF SANDSTONE RESERVOIRS

So far we have emphasized the factors influencing porosity and permeability on the grain to microscopic scale. All sedimentary deposits, however, have an inhomogeneity caused by the distribution in time and space of sedimentary facies ("architecture"), and by compaction, deformation, cementation, and the nature of pore-filling fluids. A classification system of reservoir heterogeneities can be based on their size, origin, and influence on fluid flow (early examples are Pettijohn et al. 1973; Weber 1986, p. 489) (Fig. 10.44). One of the major factors in any classification is the size of the heterogeneities, as illuminated in the scheme that follows:

- *First-order heterogeneities* (1–10 km scale), including the presence of sealing faults and the boundaries of major genetic units of sediment such as fluviatile channel-belts;
- *second-order heterogeneities* (cm to tens of m scale) which represent variation in permeability within the larger genetic units. The interbedding of shales at channel margins, or the permeability contrasts caused by the coarse–fine stratification of a point bar are examples;
- *third-order heterogeneities* (mm to m scale) result from the geometrical arrangements of individual depositional units such as bedforms producing cross-stratification. The inclined foresets of cross-sets also produce a finer scale alternation of moderate and high permeabilities, whereas the toesets of bedforms introduce essentially horizontal low permeability "breaks" or "baffles" into the reservoir (Weber 1987). *Fractures* and *stylolites* also fall within this physical scale of heterogeneity;
- *fourth-order heterogeneities* (μm to mm scale) are represented by variations in grain size and sorting, and *microscopic heterogeneities* caused by the way in which pores are interconnected or blocked.

Large scale heterogeneities of well-spacing size can often be analyzed on the basis of detailed well log correlations and by the use of sedimentological models derived from core descriptions. For smaller scale heterogeneities, cores are indispensable, since they provide information on bed thickness, style of cross-stratification, grain size, and microscopic features. The correct identification of the environment of deposition of the sediment greatly helps in an assessment of heterogeneity.

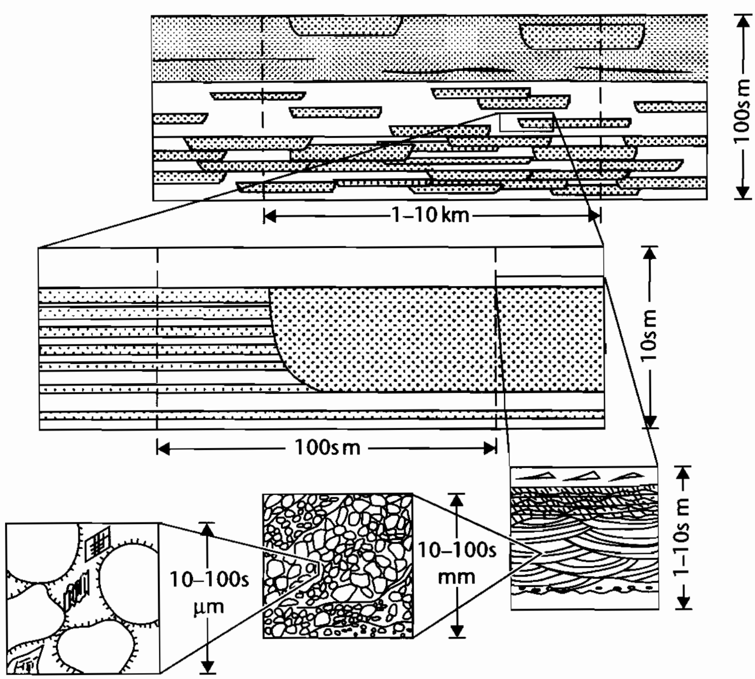


Fig. 10.44 Example of various levels of heterogeneity in a fluviatile reservoir from the km scale down to the microscopic scale.

A thorough study of the various scales of heterogeneity is essential to the efficient recovery of hydrocarbons from a reservoir but is of less direct concern to the basin analyst. A major objective of the production geologist is to supply engineers with information on the porosity and permeability structure of a reservoir rock. This is commonly done by assigning porosity and permeability values to individual cells in a numerical model of the reservoir. The petroleum engineer then performs a simulation of the flow of fluids, including hydrocarbons, through the reservoir. Where geological information on heterogeneity is poor, it is useful to use scaling relationships between bed thickness, bed width, and bed volume derived from field studies as a guide. Turbidite successions have in particular been analyzed very promisingly in this way (Rothman et al. 1994; Malinverno 1997; Talling 2001; Sinclair and Cowie 2003).

Provenance of reservoir sediment

Investigations of the source area for a sediment are called provenance studies. Provenance studies classically developed as an analysis of the mineralogy of the light fraction of siliciclastic sediments in the form of ternary diagrams of quartz (Q), felspars (F), and lithics or rock fragments (L) (e.g., Dickinson 1980; Dickinson and Suczek 1979; Ingersoll and Suczek 1979; Dickinson and Valloni 1980; Lash 1987). Variations on the standard QFL diagram are used by distinguishing between, for example, polycrystalline and other forms of quartz, or sedimentary versus volcanic rock fragments. These ternary diagrams are divided into fields representing distinct plate tectonic settings for the sandstone sample, but overlapping of some of the fields severely limits their uses. Although these techniques continue to be used, they have been supplemented by other methods including heavy mineral analysis (Mange and Maurer 1993), fission track thermochronology of detrital apatites and zircons, and isotopic studies such as U–Pb dating of detrital zircons and Sm–Nd analysis of basin sedimentary rocks. All of these techniques are directed towards understanding the mineralogy, geochronology, and thermal evolution of the source regions providing basin sediment.

The effects of *transport* of sediment on the resulting composition of a sandstone is critical to the correct interpretation of provenance. Transport in terrestrial systems invariably modifies the composition of the sand, but the effects differ markedly according to climatic zone and type of river system. Franzinelli and Potter (1983) provide an elegant study of the Amazon drainage system in this respect. Large river systems in humid and hot climates are optimal for the chemical weathering of unstable grains such as lithic fragments. As a result, the sand at the mouth of the Amazon is dominated by quartz, despite the fact that considerable proportions of lithic grains were contributed to the drainage system at the source. Other smaller or cold climate terrestrial systems on the South American continent produce relatively immature sands (Potter 1978, 1984). The marine sedimentary record is increasingly used to interpret climate change or changes in sediment routing systems in the source regions. Well-documented examples from the Indian Ocean are provided by Einsele et al. (1996), Prins and Weltje (1999), and Clift and Gaedicke (2002).

The likelihood of the presence of reservoir units of adequate quality in different basin types can therefore be broadly assessed from a knowledge of the hinterland geology and sediment dispersal systems (Kingston et al. 1983a, b). In broad outline, continental sags typically contain extensive shallow marine, fluviatile, eolian, and lacustrine reservoirs. Rifts may contain early spatially restricted and volcanic-rich reservoir units of poor quality, and younger, more extensive, fluviatile, deltaic, and marine good quality reservoirs. Passive margins have very extensive shallow marine and deltaic sands or thick carbonate reservoirs, and deep water turbiditic reservoirs. Strike–slip basins have a composition of sedimentary infill determined by the nature of the adjacent plates. Ocean–ocean boundaries generally provide poor reservoirs because of contamination by pelagic and volcanogenic material; continent–ocean and continent–continent zones have more chance of providing sources of sand. Forearc and trench sediments contain large amounts of volcanogenic material, and porosity and permeability are severely reduced during diagenesis. It must be emphasized, however, that these are broad generalizations and the practicing basin analyst should in some sense treat every basin on its own merits after a collation of all available data.

10.5 THE REGIONAL TOPSEAL

Summary

The existence of a petroleum play depends on the presence of an effective regional caprock or topseal.

The basic physical principles governing the effectiveness of petroleum caprocks are the same as those that control secondary migration of petroleum. A caprock is effective if its capillary or displacement pressure exceeds the upward buoyancy pressure exerted by an underlying hydrocarbon column. The capillary pressure of the caprock is largely a function of its pore size. This may be laterally very variable.

The buoyancy pressure is determined by the density of the hydrocarbons and the hydrocarbon column height. A caprock of extremely small pore size is required to prevent the buoyant rise of a tall underlying gas column. Hydrodynamics also affect caprock effectiveness. Loss of gas through caprocks may take place through the process of diffusion.

A worldwide survey of caprocks indicates that the most effective caprock lithologies are fine-grained siliciclastics and evaporites. Ductility is also an important requirement, particularly in tectonically disturbed areas. Salt and anhydrite are the most ductile, followed by organic-rich shales. Caprocks do not need to be thick to be effective, as long as they are laterally persistent. Similarly, depth of burial does not appear to be critical – seals may be effective at all depths. A good example of a regional caprock is the Upper Jurassic Hith Anhydrite in the Arabian Gulf area, which seals in excess of 100 billion barrels of oil in the underlying Arab reservoirs.

The conditions required for the development of regionally extensive, effective caprocks in association with reservoir rocks are frequently met in two particular depositional settings. One of these is where marine shales transgress over gently sloping siliciclastic shelves, as in the Miocene Telisa Formation shales of the Central Sumatra Basin. The other is where evaporites in regressive sabkhas regress over shallow marine carbonate reservoirs, as in the case of the Hith anhydrite of the Arabian Gulf.

10.5.1 Introduction

The regional caprock or topseal is one of the three essential ingredients of the petroleum play. The nature of the caprock determines not only the efficiency of the subsurface trapping system, but influences the migration routes taken by petroleum fluids on leaving the petroleum source rock. The continuity of the regional topseal largely determines whether the basin has a laterally or vertically focused migration system. Compared to the enormous literature devoted to reservoir rocks, and the massive effort devoted to understanding the geochemistry of source rocks, relatively little has been written on caprocks. Downey (1984) and Grunau (1987), however, provide important reviews.

10.5.2 The mechanics of sealing

The basic physical principles governing the effectiveness of petroleum caprocks are the same as those controlling secondary migration (§10.3.2.4). The physical principles themselves are relatively well understood (Schowalter 1976), though much has still to be learned about seals in general.

In §10.3.2.4, we divided the forces that control secondary migration into those that drive secondary migration, and those that restrict it. The main driving force is *buoyancy*, caused by the fact that petroleum fluids are generally less dense than formation pore waters. The main restricting force to the movement of a globule or slug of petroleum through a porous rock is its *capillary* or *displacement pressure*. This depends primarily on the size (radius) of the pore throats. A rock will seal an underlying petroleum accumulation if the displacement pressure of its *largest* pore throats equals or exceeds the upwardly directed buoyancy pressure of the petroleum column (Fig. 10.45). The seal potential or capacity of a caprock can be expressed as the maximum petroleum column height that it will support without leakage. Owing to subsurface density differences of oil and gas, caprocks can support much larger oil columns than gas columns, other things being equal.

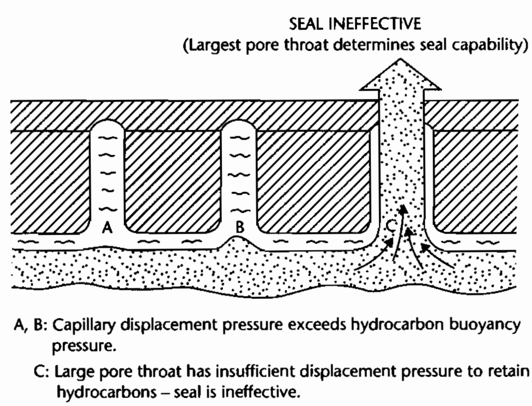


Fig. 10.45 Diagrammatic illustration of the effect of the largest pore throat size on sealing capacity of caprocks (modified from Downey 1984).

The displacement pressure of a piece of caprock can be measured directly in the laboratory by mercury-injection techniques, or can be estimated from the rock porosity and permeability. These data are useful in evaluating seals, but a very severe limitation is caused by the doubtful representativeness of the analyzed sample with respect to the entire sealing surface of the trap. Pore sizes are likely to vary considerably over the lateral extent of the caprock, so a core sample tells us little about the sealing capacity of the caprock as a whole. The existence of large pore networks is critical; these represent the weakest points of the seal. As a result of these difficulties, seal capacity calculations are subject to wide ranges of error.

10.5.2.1 The effect of hydrodynamics and overpressured caprock

Under hydrodynamic conditions, the driving forces for migration or leakage are modified. Hydrodynamic flow may either increase or decrease the driving pressure against seals, thus modifying the petroleum column heights the seal can support. When the hydrodynamic force has an upward vector, it acts in support of buoyancy; when it is downward it diminishes the effect of buoyancy on the seal. Hydrodynamic effects on seal capacity may, however, for all practical purposes, be ignored except in those basins with clear evidence of hydrodynamic conditions operating at the present day. In the Powder River Basin of Wyoming, Berg (1975) has shown that hydrodynamic down-dip flow has assisted the lateral sealing of the Recluse Muddy and Kitty Muddy fields.

The existence of overpressure in a shale caprock may create a local pore pressure gradient that greatly assists its capacity to seal adjacent normally pressured reservoirs. Studies in the Niger delta (Weber et al. 1978) and Gulf Coast (Stuart 1970) provide field examples.

10.5.2.2 Loss of petroleum through caprocks by diffusion

Gas may diffuse through water-filled caprocks over geological time scales (Leythaeuser et al. 1982). In a study of the 68 billion cubic feet Harlingen gas field in Holland, it is estimated that half of the accumulation would be lost by diffusion through the 400 m thick shale caprock in 4.5 Myr. Thus, gas fields overlain by water-saturated shale caprocks are likely to be ephemeral phenomena unless continuously topped up by active generation in the area. If losses by diffusion are as severe as Leythaeuser et al. (1982) suggest, there are some difficulties in explaining the existence of gas fields charged and reservoired in very old sequences, such as the Lower Paleozoic.

10.5.3 Factors affecting caprock effectiveness

The effectiveness of caprocks worldwide may be examined in terms of their lithology, ductility, thickness, lateral continuity, and burial depth.

10.5.3.1 Lithology

Nederlof and Mohler (1981), in a statistical analysis of 160 reservoirs/seals, found that caprock lithology was of considerable importance in influencing seal capacity. Caprocks need small pore sizes, so the vast majority of caprocks are fine-grained siliciclastics (clays, shales), evaporites (anhydrite, gypsum, halite) and organic-rich rocks. Other lithologies such as argillaceous limestones, tight sandstones and conglomerates, cherts and volcanics may also seal, but they are globally far less important, are frequently of poor quality, and geographically of limited extent.

Grunau (1987) compiled information on the caprock lithologies of the world's 25 largest oil and 25 largest gas fields. There was a roughly equal split between shales (13) and evaporites (12) for the 25 oil fields. For the gas fields, shales (16) predominated over evaporites (9).

About 40% of the ultimately recoverable oil reserves from the world's giant oil fields are capped by evaporites, and 60% by shales (Grunau 1987). For gas, the corresponding percentages are 34% for evaporite caprocks and 66% for shales. The majority of giant oilfields with evaporite caprocks are located in the Middle East and North Africa, while shale caprocks to giant *oil fields* are more ubiquitous, and include Alaska, western Canada, California, the Gulf Coast, Mexico, Venezuela, the North Sea, the Soviet Union, Indonesia, and Brunei. Evaporite caprocks to giant *gas fields* are geographically more widely distributed, and apart from the Middle East and North Africa, include the Soviet Union, Netherlands/southern North Sea, and Brazil.

10.5.3.2 Caprock ductility

Ductile caprock lithologies are less prone to faulting and fracturing than brittle lithologies. Caprocks are placed under substantial stress during periods of structural deformation, including the deformation responsible for trap formation. During the formation of a simple anticline, for example, tensional fractures may occur in brittle caprocks in the crestal parts of the fold. Ductility is, therefore, a particularly important requirement of caprocks in strongly deformed areas such as fold and thrust belts.

The most ductile lithologies are evaporites, and the least ductile cherts (Table 10.5). This may explain the extraordinary success of evaporites as caprocks. A high kerogen content appears to enhance the ductility of shale caprocks. Many source rocks, therefore, also serve as seals. Ductility is also a function of temperature and pressure. Evaporites may be brittle at shallow depths, but very ductile at depths of over 1 km.

10.5.3.3 Caprock thickness

A small thickness of fine-grained caprock may have sufficient displacement pressure to support a large hydrocarbon column. Thin caprocks, however, tend to be laterally inpersistent; thus a thick caprock substantially improves the chances of maintaining a seal over the entire prospect, or even over the entire play fairway or basin. Typical caprock thicknesses range from 10s of m to 100s of m (Grunau 1987). Very large volumes of petroleum may be sealed by relatively modest thicknesses of caprock. For example, the 3 m-thick Ahmadi shales seal the 74 billion barrel Burgan field in Kuwait; the 20 m-thick Arab C-D anhydrite seals the Arab D-Jubaila main reservoir of the Ghawar field in Saudi Arabia, the world's largest oil field (approx 80 billion barrels); the 33 m-thick Cap-Rock anhydrite seals the Asmari oilfields of the Iranian Zagros Fold Belt. For gas reservoirs, a thick caprock reduces the risk of substantial losses by diffusion.

Table 10.5 Ductility of caprocks (Downey 1984).

Caprock lithology	Ductility
Salt	Most ductile
Anhydrite	↑
Organic-rich shales	
Shales	
Silty shales	
Calcareous mudstones	↓
Cherts	Least ductile

10.5.3.4 Lateral seal continuity

In order to provide good regional seals, caprocks need to maintain stable lithological character (and hence capillary pressure and ductility characteristics) and thickness over broad areas. Most prolific petroleum provinces contain at least one of these regional seals. The search for petroleum in these basins may be focused on the base of the regional seal, rather than on any particular reservoir horizon. The lateral variability of the regional seal may be studied using wireline log information and seismostratigraphic analysis.

Some depositional environments and basin settings are more conducive to the establishment of thick and effective regional caprocks than others. Two of these will be discussed in §10.5.4. Of particular importance are the distinctive depositional environments that give rise to evaporite deposition (§8.5).

10.5.3.5 Burial depth of caprocks

The present burial depth of caprocks does not appear to be an important factor in influencing seal effectiveness. Grunau (1987) presents histograms showing the seal depths of the world's giant oil and gas fields. Almost half of the ultimately recoverable reserves of oil occurs in the 1000–2000 m depth range, and 31% in the 2000–3000 m range. The world totals are, of course, strongly influenced by the Middle East. There are, however, important regional variations. The most striking variations are North America, where over half of the ultimately recoverable oil reserves in giant fields are at depths of <1000 m, and the Far East and Australasia, where, in contrast, 72% is at depths >3000 m. For giant gas fields, the depth distribution is similar at the world level, and regional variations are slightly less strong. As Grunau (1987) points out, deep gas is probably much more abundant in nature than the statistics indicate, but in many cases it is uneconomic to explore for or to develop.

The overall impression, therefore, is that seals may be effective at all depths. The requirement always is that a unit of high displacement pressure and ductility is present over wide areas. This has got little to do with *present-day* depth of occurrence. However, we know that shale pore diameters do decrease with burial, particularly over the first 2 km (see §9.2). The *maximum attained depth of burial* of shale caprocks is, therefore, likely to have an influence on sealing capability. Many shallow oil accumulations occur in structures that have undergone significant uplift, bringing well-compacted caprocks close to the surface. Provided these caprocks retain their ductility and avoid brittle deformation through the uplift period, there is no reason why they should not be effective caprocks. In the *Duri* field (3.9×10^9 barrels recoverable) of the Central Sumatra Basin, Indonesia, the oil-bearing lower Miocene Bekasap Formation sands occur at depths of only 100 m below ground surface over the crest of the structure, sealed above by lower to mid-Miocene Telisa Formation shales. Furthermore, the overlying Duri Formation reservoirs in the field occur at depths of less than 30 m. The *Minas* field (4.3×10^9 barrels recoverable) in the same basin is deeper, with the lower Miocene Sihapas A-1 sand at approximately 700 m. This reservoir is sealed from younger water-bearing sands in the Upper Telisa by 70 m of Telisa Formation shales.

10.5.3.6 Case study: the Hith anhydrite regional topseal of the central Arabian Gulf

A classic example of the importance of regional seals on the location of oil and gas is provided by the Middle East (Murris 1980) (Fig. 10.46). The two main regional caprocks are the Tithonian Hith anhydrite and the Albian Nahr Umr Shale. The Hith anhydrite is the regional topseal to the prolific Upper Jurassic Arab reservoirs, sealing well in excess of 100×10^9 (billion) barrels of recoverable oil reserves. Not only do prolific accumulations in the underlying Arab reservoirs demonstrate the effectiveness of the Hith anhydrite as a seal, but so also does the general *lack* of accumulations in the overlying Lower Cretaceous where the Hith is present. The Hith is occasionally breached by faulting, allowing upward migration of oil from the Upper Oxfordian–lower Kimmeridgian Hanifa source rock (for example, at Idd el Shargi in Qatar). Oils in Arab reservoirs have been confidently traced back to Hanifa source rocks, using a broad range of geochemical parameters. In the east of the central Gulf area, where, at and beyond the Upper Jurassic shelf edge the Hith is depositionally absent, hydrocarbons generated in the Hanifa have penetrated upwards into Lower Cretaceous reservoirs. Figure 10.47 shows the areal distribution of Upper Jurassic and Lower

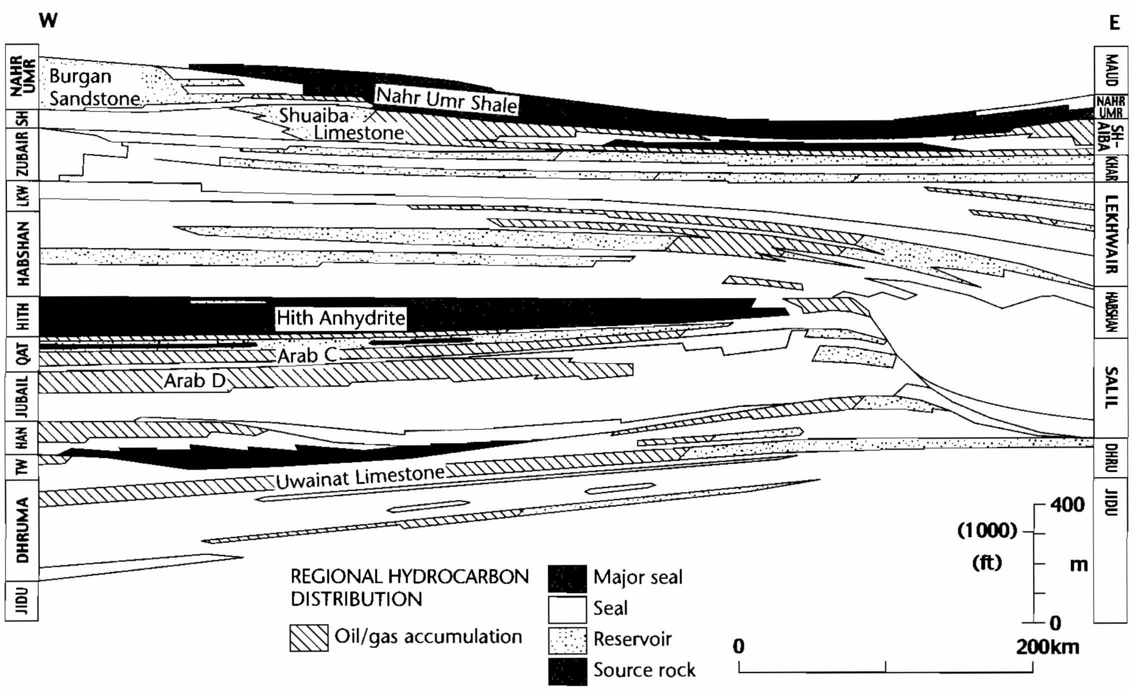


Fig. 10.46 Relationship of oil and gas accumulations to the regional topseals in the Middle Jurassic to Albian sequences, central Gulf area, Middle East (after Murris 1980). The Upper Jurassic Hith Anhydrite seals the prolific underlying Arab reservoirs, which contain over 100×10^9 (billion) barrels of recoverable oil reserves. The Hith anhydrite terminates by facies change towards the Upper Jurassic shelf edge in the east of the area. The oil has been sourced from the Upper Jurassic Hanifa. (Reproduced with permission from Murris 1980.)

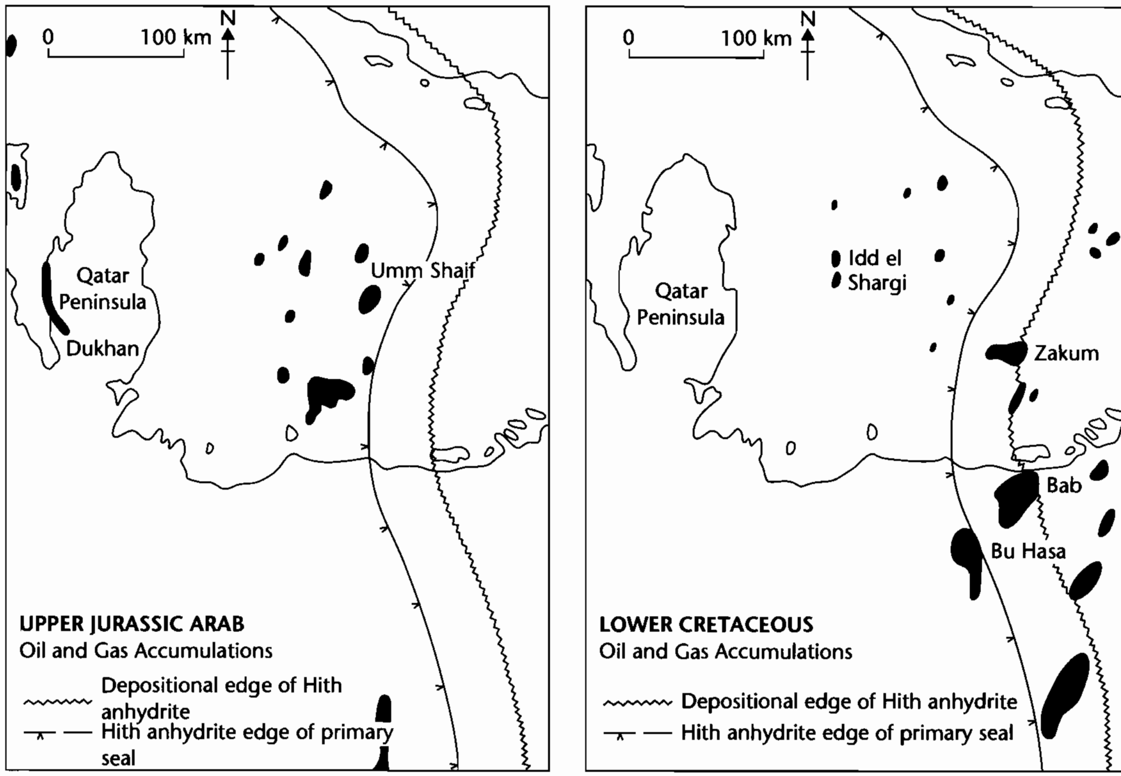


Fig. 10.47 Areal distribution of oil and gas accumulations in the central Gulf area in relation to the Hith anhydrite caprock (adapted from Murris 1980). Arab accumulations are closely related to the occurrence of the Upper Jurassic Hith topseal. Lower Cretaceous accumulations also occur above the Hith where it is locally breached.

Cretaceous accumulations in the central Gulf area, in relation to the main seal edge and depositional edge of the Hith anhydrite. An unknown but probably high proportion of the Lower Cretaceous reservoired oil in the east of the area has been sourced, however, from the Shuaiba source rock, which is mature only in this eastern area. This contribution, therefore, is quite independent of the presence or absence of the Hith anhydrite.

10.5.4 The depositional settings of caprocks

We have seen in the previous pages that the requirements for good regional caprocks are the maintenance of stable lithology and ductility over broad areas. A stratigraphic unit is not a caprock unless it seals an underlying reservoir; thus the ideal regional caprock maintains its sealing characteristics over wide areas but also occurs in stratigraphic association with reservoirs. These conditions are liable to be met particularly in the following two types of depositional setting.

1 *As transgressive marine shales on gently sloping siliciclastic shelves*: these regionally extensive shales may form an excellent seal to basal transgressive sandstone reservoirs. This petroleum play, occurring in the *wedge-base position* of the depositional sequence, as described by White (1980), is a very successful one throughout the world (Fig. 10.48a). The marine transgression may flood wide areas of low-lying coastal flats, and isolate the marine shelf from supplies of coarse clastics. Thus the *transgressive systems tract* (§8.2.3), extending from the time at which the paleoshelf begins to be onlapped, to the time of sea-level

highstand, is frequently an ideal location for the development of regional caprocks. However, sandy transgressive systems tracts, which line the lower depositional sequence boundary, may act as "thief-zones", allowing the migration up-dip of petroleum. The correct prediction of shales in the transgressive systems tract is therefore essential. An example of an excellent and extensive transgressive marine shale caprock is the lower-mid Miocene Telisa Formation of the highly productive Central Sumatra Basin, Indonesia. Over 12×10^9 barrels of recoverable oil reserves have been discovered in this basin, much of it as a result of the development of the Telisa shale regional topseal. The Telisa is a marine shelf unit deposited as a result of the flooding of lower Miocene sand-rich deltas (for example, the Bekasap-Duri and Sihapas deltas). In this way, a prolific reservoir-topseal doublet was formed.

2 *As evaporitic deposits on regressive supratidal sabkhas and in evaporitic interior basins*: in siliciclastic systems, the regressive wedge-top deposits (*sensu* White 1980) (Fig. 10.48b), or the late highstand systems tract or shelf margin wedge systems tract (see §8.2.3) are of generally poor seal quality, comprising shallow marine and coastal sands and

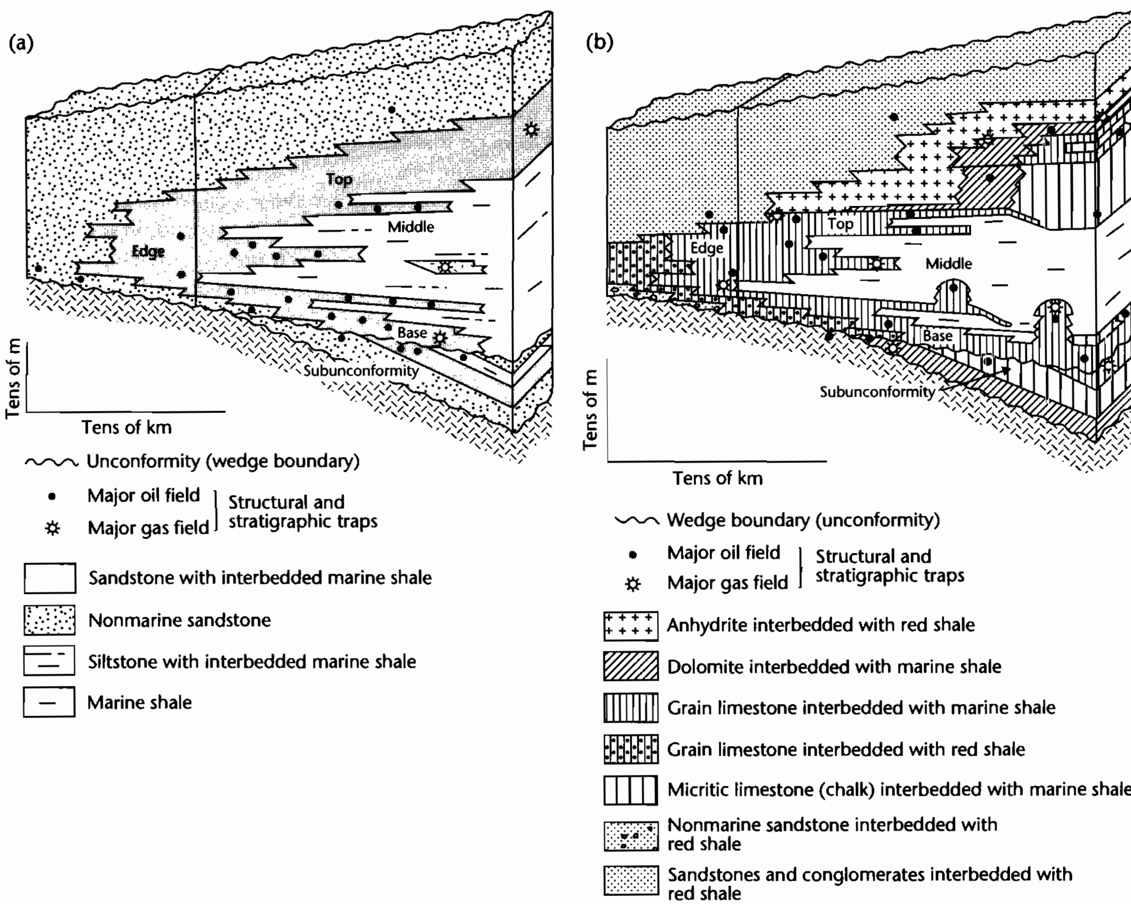


Fig. 10.48 (a) Distribution of facies in the sand–shale wedge of White (1980), corresponding to a continental to marine siliciclastic depositional sequence. Wedge-base, wedge-edge, wedge-middle, wedge-top, and subunconformity positions may be identified; (b) Distribution of facies in the carbonate-shale wedge of White (1980), corresponding to an arid continental-peritidal to shallow marine carbonate-evaporite depositional sequence. A prominent feature is the thick evaporite unit in the wedge top, which may form an excellent regional topseal.

nonmarine deposits. These may form excellent reservoirs, but they do not make good seals. In carbonate systems, however, extensive evaporitic sabkhas may gently prograde across flat marine carbonate platforms, providing extensive and excellent quality seals. The Tithonian Hith anhydrite of the Arabian Gulf is a good example (Murris 1980). As the climate became arid in the Tithonian, the shallow carbonate platform in which the prolific Arab reservoirs were deposited was replaced by an extensive sabkha (§10.4.2).

Evaporites develop through the interaction of paleoclimate and paleogeography. They may develop on supratidal sabkhas (§8.5.3), in evaporitic continental interior basins (§8.5.2) or in wide rifted basins during the early stages of seafloor spreading (§8.5.2) (e.g., the Albian salt of the South Atlantic). Clear paleoclimatic and paleogeographic controls can normally be determined. Shale caprocks may be deposited in a wider range of depositional environments, ranging from lacustrine (§8.5.2) through marine shelf (§8.5.4) to bathyal (§8.5.5).

10.6 THE TRAP

Summary

The final requirement for the operation of an effective petroleum play is the presence of traps within the play fairway. A trap represents the location of a subsurface obstacle to the migration of petroleum towards the Earth's surface, which causes its local concentration. The petroleum exploration industry is primarily concerned with the recognition of these sites of petroleum accumulation.

Traps are classified into structural, stratigraphic, and hydrodynamic traps.

Structural traps are those caused by tectonic, diapiric, gravitational, and compactional processes, and represent the habitat of the bulk of the world's already discovered petroleum resources. The development of most structural traps can be understood in terms of basin-forming mechanics and the ensuing burial history of the basin-fill. Examples are the contractional folds of the Zagros fold belt of Iran and the Wyoming–Idaho fold–thrust belt, the inversion anticlines of Sumatra, the extensional tilted fault blocks of the North Sea, the extensional rollovers and fault traps of the Niger Delta and US Gulf Coast, the compactional drape anticlines of the North Sea, and the salt domes and related diapiric structures of the Gulf Coast. The majority of the world's giant oil fields have so far been found in anticlinal structural traps.

Stratigraphic traps are a diverse group in which the trap geometry is essentially inherited from the original depositional morphology of, or discontinuities in, the basin-fill, or from subsequent diagenetic effects. Large volumes of *undiscovered* petroleum may reside in stratigraphic traps, and their discovery will require a very high level of geological expertise. Examples of stratigraphic traps are the fluvial channels and barrier bars in the Cretaceous basins lying along the east flank of the Rockies, the Tertiary submarine fans of the North Sea; the carbonate reefs of the western Canadian Devonian, southern Mexico and Arabian Gulf; the subunconformity truncation traps exemplified by the Prudhoe Bay (Alaska) and East Texas fields; and the subunconformity paleotopographic traps of the Gulf of Valencia, Spain. Diagenetic traps include those formed by mineral diagenesis, petroleum tar mat formation, and permafrost and gas hydrate formation.

Hydrodynamic traps are those formed by the movement of interstitial fluids through basins and, in a worldwide context, tend to be relatively uncommon. Hydrodynamic effects, however, are important in some foreland basins.

Not only must a sealed trap geometry be present for the existence of a petroleum trap, but the timing of its development must also be considered. The geometry must be present prior to the petroleum charge in order to trap petroleum. Thus, an understanding of the history of individual trap growth, together with the burial and thermal history of the basin, is essential to the evaluation of petroleum prospects.

10.6.1 The formation of traps for petroleum: introduction

The final requirement for the operation of an effective petroleum play is the presence of traps within the play fairway. A trap exists where subsurface conditions cause the concentration and accumulation of petroleum. After petroleum is generated and expelled from source rocks, it will move from sites of high potential energy to sites of low potential energy. This process ultimately leads to the loss of the petroleum at the Earth's surface. Subsurface traps *en route* may be considered local (and temporary) potential energy minima. In these places, the migration route of petroleum is obstructed.

The commercial exploitation of petroleum resources depends on the concentration and accumulation of petroleum in traps. The petroleum industry has been dominated by exploration for specific subsurface geometries that are diagnostic of the presence of a trap. The recognition of these geometries, frequently on seismic sections, has been the goal of explorers for decades. The same basic physical principles apply to trapping as to secondary migration and seals. A trap is formed where the capillary displacement pressure of a seal exceeds the upward-directed buoyancy pressure of petroleum in the adjoining porous and permeable reservoir rock (§10.3.2.4 and §10.5.2).

Both oil and gas may occur in a trap; the gas lies above the oil because it is less dense. If a trap is charged first with oil, and then with gas (for example, as a result of increasing source rock maturity), the expanding gas cap may displace oil downwards past the spill point(s) of the trap. The oil may then migrate up-dip to the next available trap. Thus, traps may contain greater proportions of oil relative to gas as the distance from the source kitchen increases. This is the so-called *Gussow principle*.

Figure 10.49 shows some terms commonly used in the description of traps. Note that the trap illustrated is not full-to-spill. A *gas cap* overlies an *oil leg*, but the (structural) spill point is some distance below the *oil–water* contact.

10.6.2 Trap types

The main purpose of trap classification is to allow comparison between one prospect, or one play, and another. A particular trap type in a basin may be characterized by a distinctive field size distribution and drilling success ratio. Trap classification (Table 10.6) more readily allows the drawing of geological analogies which may be useful in estimation of prospect and play petroleum volumes and risk. The main subdivision is between *structural traps*, in which the majority of the world's petroleum resources have been found, and *stratigraphic traps*. The classification is based essentially on the *process* causing the formation of the trap, rather than its geometry. If the geological processes operating in a basin are known, therefore, a particular suite of traps may be predicted. Particular structural traps, for example, can be related to tectonic setting and basin-forming mechanics (Chapters 3–6). The detection of stratigraphic traps, on the other hand, is dependent on a good understanding of basin evolution and the stratigraphy of the basin-fill (Chapters 7–9).

Table 10.6 Classification of trap types based on the process causing trap formation, rather than trap geometry.

Structural	Tectonic	Extensional
		Contractional
	Compactional	Drape structures
	Diapiric	Salt movement
		Mud movement
	Gravitational	
Stratigraphic	Depositional	Reefs
		Pinch-outs
		Channels
		Bars
	Unconformity	Truncation
		Onlap
	Diagenetic	Mineral
		Tar mats
		Gas hydrates
		Permafrost
Hydrodynamic		

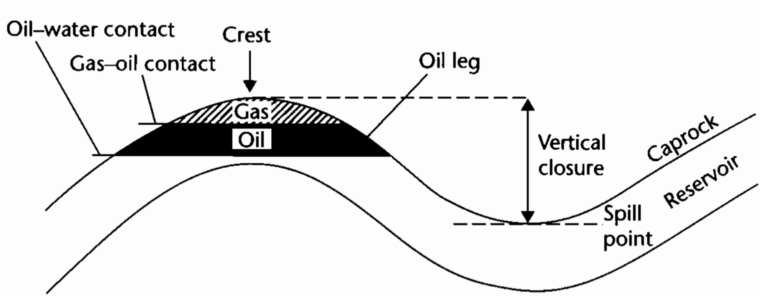


Fig. 10.49 Terms commonly used in the description of traps. A gas cap overlies an oil leg, and the trap in this case is not filled down to its structural spill point.

Structural traps are those caused by tectonic, diapiric, gravitational, and compactional processes. The essential point is that movement has occurred in the basin-fill some time after its deposition. *Stratigraphic traps* are those in which the trap geometry is inherited from the original depositional morphology of the basin-fill, or from diagenetic changes that took place subsequently. The best-known stratigraphic traps are caused by facies change or related to unconformities, but we have also included here traps sealed by the up-dip clogging of pore-space by biodegraded oil, gas hydrates or permafrost. *Hydrodynamic traps* are caused by the flow of water through a reservoir/carrier bed. They may be important in some basins, but are generally rare. More than one process may contribute towards the formation of a trap. Examples are hydrodynamic closures developed on structural noses, onlap, and pinch-out traps combined with structural deformation, and channel sands developed on unconformity surfaces. Furthermore, different trap types may be genetically related. A reef, for example, may be overlain by a compactional (drape) anticline.

10.6.2.1 Structural traps

STRUCTURAL TRAPS FORMED BY TECTONIC PROCESSES

Contractional folds and thrust-fault structures

Contractional folds occur in areas undergoing tectonic compression, and are generally associated with convergent plate boundaries, particularly where continent–continent collision has taken place (Chapter 4). They may also develop where transpression occurs along strike–slip boundaries (Chapter 5).

From a petroleum viewpoint, the most prolific zone of contractional folding is the external zone of the *Zagros Mountains in Iran* (Falcon 1958; Hull and Warman 1970) (Fig. 10.50). The main producing reservoir is the lower Miocene Asmari Limestone, which owes its prolific productivity to tectonically induced fracturing. The brittle limestone reservoir is overlain by the ductile evaporite caprocks of the Miocene Lower Fars Group. The folds

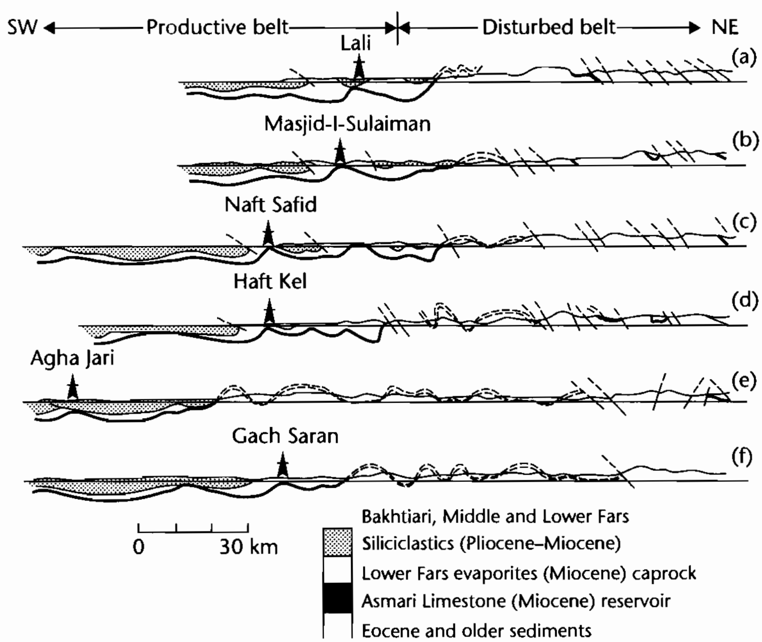


Fig. 10.50 Cross-sections across the Zagros foldbelt of Iran (after Falcon 1958). The folds are large and, at surface, relatively simple. The main producing reservoir is the lower Miocene Asmari Limestone; it has been tectonically fractured, and is sealed by the ductile Lower Fars Group evaporites.

are up to 60 km long and relatively simple where dramatically exposed in outcrop. At depth, however, they are considered to be tighter and associated with thrust faults which sole out onto a basal detachment (Fig. 10.51), possibly in the Hormuz Salt.

Another example of an area of productive contractional fold structures is the *Wyoming Thrust belt*, USA. The Painter reservoir field (Lamb 1980), discovered in 1977, is a large overturned anticline developed in the hanging wall of the Absaroka Thrust (Fig. 10.52). The producing reservoir is the Triassic–Jurassic Nugget Sandstone, which has been thrust over the Cretaceous. The field was found in a seismically defined structure along trend and 16 km south of the previously discovered Ryckman Creek field, which also produces from the Nugget. As can be seen from Figure 10.52, the Painter structure has no surface expression because it is overlain by the Bridger Hill detachment and a Cretaceous unconformity. It owes its discovery to an improvement in seismic processing techniques in the mid-1970s, which allowed subsurface closure to be detected.

Surface outcrop lithology and terrain have a large influence on the quality of seismic data in fold–thrust belts. Subsurface accumulations may be very difficult to find in those areas where surface structure bears little or no relation to subsurface structure, and where surface or subsurface conditions (karstified limestone, volcanics, rugged terrain) prevent the acquisition of good-quality seismic data.

Anticlines may also develop in areas of local contraction along strike–slip systems. The Wilmington field in the Los Angeles Basin, California, is such an example (Mayuga 1970). It is developed along the San Andreas Fault system. Transpressional anticlines are arranged *en echelon* and are very strongly faulted: they depend on the presence of thick caprocks to seal reservoirs across fault planes. Other examples of highly complicated faulted anticlines that have developed along predominantly strike–slip fault systems are probably the large Seria and Champion fields of Brunei. These fields are located on the relatively proximal part of the Miocene–Recent Baram Delta, and are not only subdivided into a large number of fault compartments but also contain numerous stacked deltaic reservoirs. Some component of shale diapirism is present in the development of Champion.

Some contractional anticlines have developed as a result of the reversal of movement along old extensional faults (see Cooper and Williams 1989). These are known as *inversion anticlines*. The evidence for the earlier extensional history is usually the thickening of sediments towards the fault plane during its period of growth. Good examples are the so-called "Sunda" folds of some Indonesian basins, for example, central Sumatra. Inversions tend to occur in areas where relatively subtle

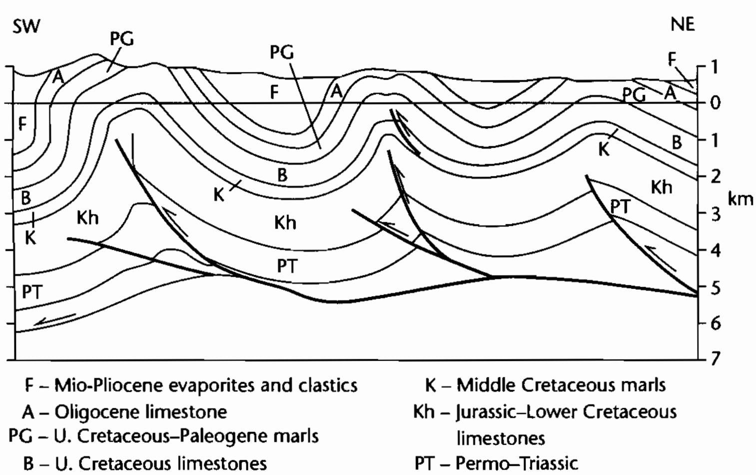


Fig. 10.51 Interpretation of the relationship of Zagros folds to structure at depth, showing the soling out of the thrust faults onto a basal detachment (after Bailey and Stoneley 1981). Similar listric fault styles typify the thrust belts of the western United States (e.g., Idaho–Wyoming) and the Canadian Rockies of Alberta and British Columbia.

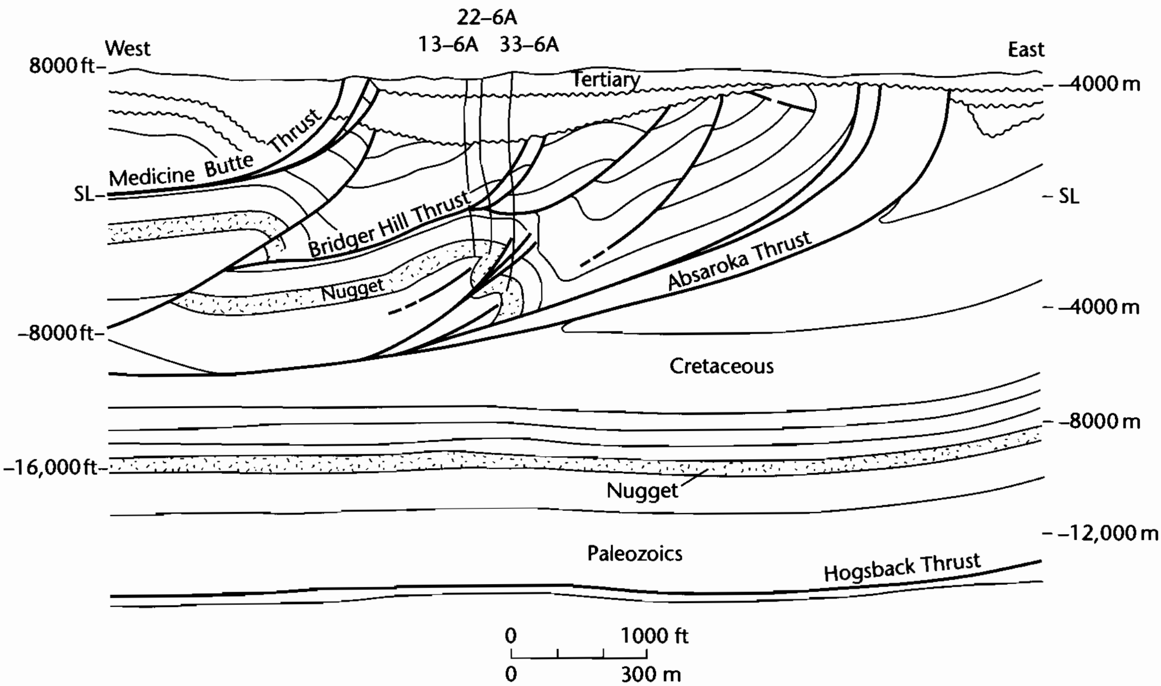


Fig. 10.52 Interpretation of the structure of the Painter Reservoir Field, Idaho–Wyoming thrust belt. The Painter structure has no surface expression, but was identifiable from seismic data. The producing reservoir is the Triassic–Jurassic Nugget Sandstone.

changes in the regional stress field cause reversal of movement along faults, and are therefore frequently associated with fault systems that have a strong strike–slip component. Petroleum charge into inversion anticlines may be a problem if a closure did not exist at the time of extension. Migration will tend to be away from the site of the inversion anticline during the extensional phase, and inversion of the basin tends to stop further petroleum generation. Charge may result from the postinversion remigration of petroleum.

Traps may develop along contractional faults without any element of folding (Fig. 10.53). These may be in the hangingwall or footwall of the fault, and depend for closure on the juxtaposition of sealing lithologies, or on the sealing of the fault zone itself, for example as a result of a finely powdered fault gouge or cemented zone. To complete the trap, closure is also needed in the third dimension, i.e., into the plane of the paper in Figure 10.53. This is frequently produced by slight curvature or angularity in the map view of the fault plane, or by the intersection by further faults.

The footwall has sometimes provided an exploration target in thrust belts. These traps are very difficult to define, mainly due to velocity variations caused by the presence of the overthrust sheet, which make seismic interpretation very difficult. Many dry holes have been drilled on velocity "pull-ups" in subthrust positions – mere illusions of the presence of a trap.

Extensional structures

Extensional structures form a very important group of traps, being responsible for many of the fields discovered in basins that have experienced a phase of rifting in their geological history (Chapter 3). We will deal in this section only with structural traps resulting from extension of the basement, that is, in stretched rift basins. The extensional structures occurring, for example, in delta sequences that developed in the postrift stage on passive margins are covered in the section on gravitational structures.

Rollover anticlines may develop in association with basement-controlled growth faults. The Vicksburg flexure

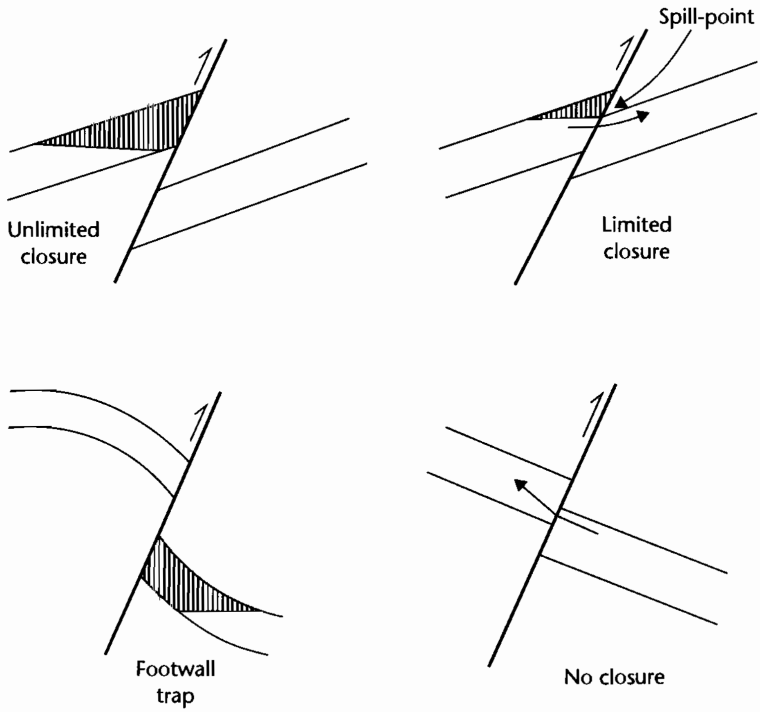


Fig. 10.53 Traps formed by high-angle reverse (contractional) faults. Juxtaposition of permeable bed limits closure. For maximum closure, fault throw needs to be large in relation to reservoir thickness. All of the illustrated trap types also require closure in the third dimension, that is, into the plane of the paper. After Bailey and Stoneley (1981).

in south Texas is an example. Very large sediment thickness changes occur across the fault zone, particularly in the Oligocene section. Large quantities of oil and gas are trapped in rollover anticlines, fault traps, and stratigraphic pinch-outs.

The most prolific play in the East Shetland Basin of the North Sea province occurs in extensional *tilted fault blocks*. The giant Statfjord field (*c.* 3 billion barrels recoverable), the largest in the North Sea, contains Lower Jurassic Statfjord Formation sandstone reservoirs in a large, westward tilted fault block that has been eroded at its crest to produce a series of Late Jurassic so-called "Kimmerian" unconformities (Kirk 1980) (Fig. 10.54). Block faulting is responsible for the uplift and erosion of the east flank of Statfjord. The fault block is onlapped by Upper Jurassic Kimmeridgian source rocks, which, together with Lower Cretaceous shales, form the caprocks to the field. The source rocks were deposited in a restricted basin to the west that was bounded to the east by the uplifted Statfjord block, and to the west by the Hutton/Murchison block.

The main down-to-the-east bounding fault on the east flank of Statfjord has a total displacement of over 1800 m at Statfjord Formation level, and also controls the location of the giant Brent field, only 20 km and on trend to the south. The Statfjord field has a total areal extent of 81 km^2. The trap is a result of truncation of the Brent reservoir at the unconformity surface, and could be considered as stratigraphic. The Statfjord reservoir, however, relies on fault closure. The field is therefore a huge combination structural–stratigraphic trap.

The Ninian field to the southwest is another of the many examples in the East Shetland Basin of this style of trap – the eroded rotated fault block (Albright et al. 1980). As in the Brent Formation reservoir in the Statfjord field, the trap at Ninian is produced primarily by the truncation of Mid-Jurassic reservoirs at Upper Jurassic and Cretaceous unconformities (Fig. 10.55).

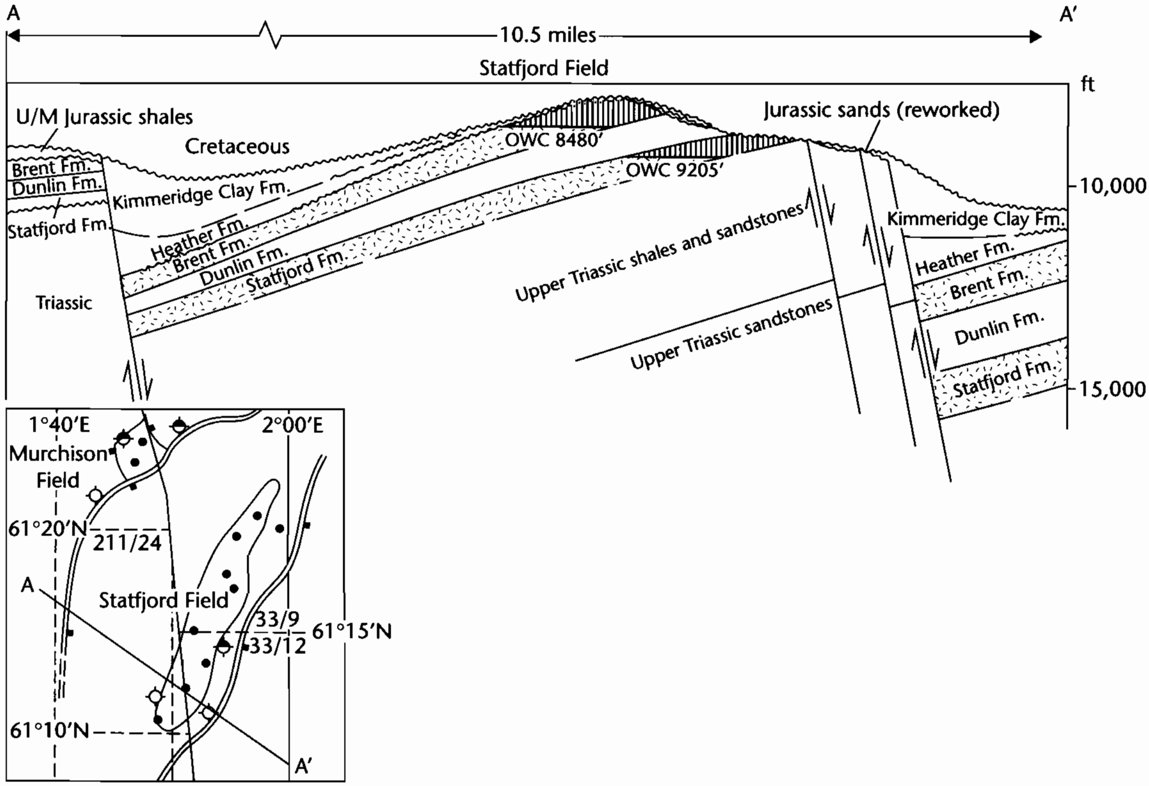


Fig. 10.54 Schematic structural cross-section across the Statfjord Field, North Sea (after Kirk 1980). Statfjord is a large westward-tilted fault block that has been strongly eroded at its crest. The trap at Brent Formation level is formed by seal at the erosional unconformity, but the deeper Statfjord Formation reservoir depends on fault closure.

Several varieties of extensional fault trap are shown diagramatically in Figure 10.56; closure is dependent on the juxtaposed lithology. It is clearly advantageous for the throw of the fault to exceed the gross reservoir thickness. The sealing or nonsealing properties of the fault plane itself are discussed in the section on gravitational structures. It is important to consider the juxtaposed lithology over the whole length of the fault trap. An "Allan" fault plane map (Allan 1980) shows the intersection of both footwall and hangingwall lithostratigraphic units onto the fault plane. In Figure 10.57, the intersection of the spill point of the footwall reservoir onto the hangingwall is at 1720 m; closure might have been mapped down to 1740 m had the geometry of the hangingwall been ignored, resulting in an overestimation of the size of the trap. A more complicated schematic is shown in Figure 10.58; petroleum migrates several times across the fault plane to higher structural levels.

Gravitational structures

The most important gravitational structure that forms petroleum traps is the rollover anticline into listric growth faults, occurring particularly in delta sequences. These structures are not caused by extension in the basement, but are due to instability in the sedimentary cover and its movement under gravity. They are most prone to form where a level of undercompacted (overpressured) clays or ductile salt occurs at depth, into which the growth faults sole out, and which is overlain by a thick succession of more competent sedimentary rocks. These conditions are commonly created in thick, progradational delta sequences, as in the Gulf of Mexico and Niger Delta (Fig. 10.59).

The roll-over anticline is the least risky trap for petroleum. Growth faulting may also give rise to *fault traps*. The integrity of the trap depends on the juxtaposition of a

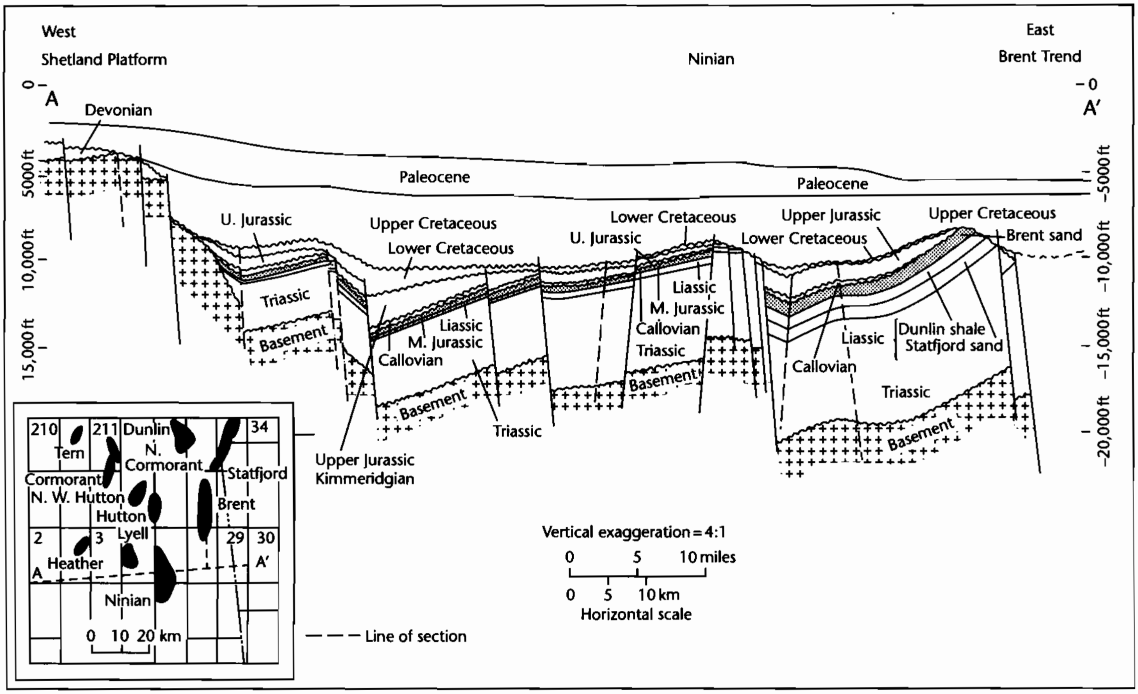


Fig. 10.55 Structural cross-section across the eroded, tilted fault blocks of the Ninian area, East Shetland Basin, North Sea (after Albright et al. 1980). This is a common and successful trap type in the North Sea.

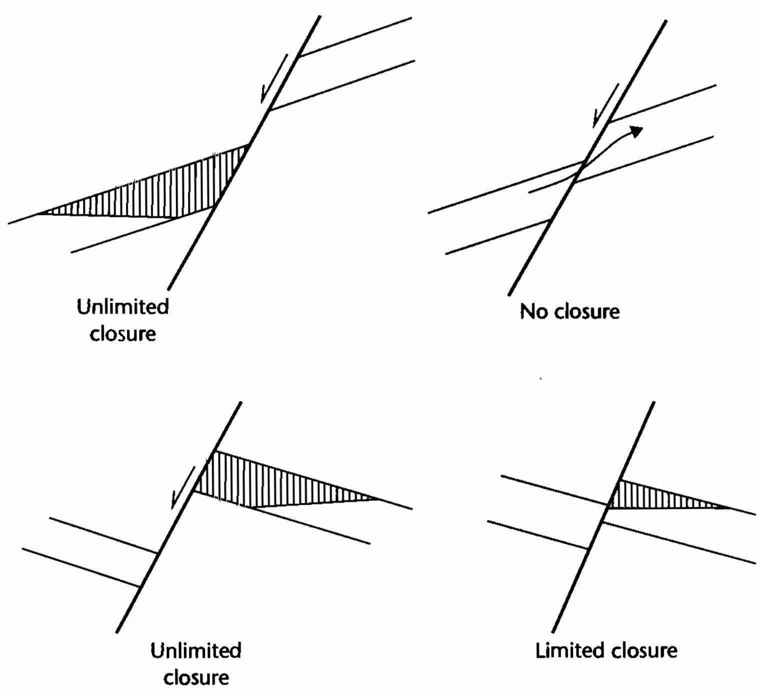


Fig. 10.56 Traps formed by extensional faults (after Bailey and Stoneley 1981). Seal depends on the lithologies juxtaposed against the reservoir across the fault plane. Ideally, fault throw should exceed gross reservoir thickness.

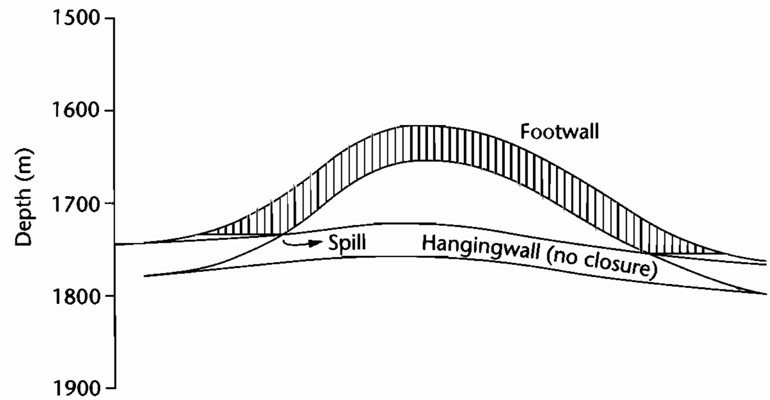


Fig. 10.57 Simple "Allan" fault plane map showing intersection of permeable lithological units in footwall and hangingwall onto fault plane. The actual spill point may lie at a position above the mapped closure in the footwall, and is controlled by the geometry of the hangingwall.

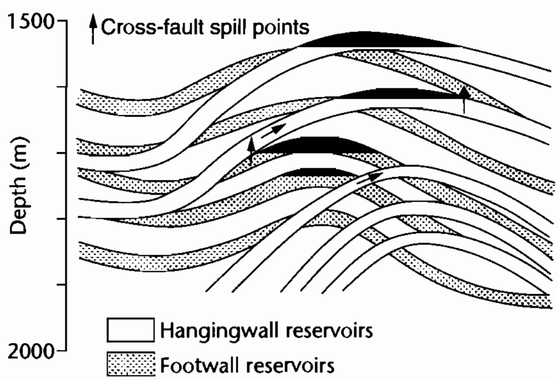


Fig. 10.58 "Allan" fault plane map showing intersection of reservoir strata in footwall and hangingwall to the fault plane. These intersections determine the spill points at each reservoir level. Petroleum may migrate several times across the fault plane, each time moving to higher structural levels.

shale seal across the fault plane, so these traps tend to be effective on those parts of the delta where the sand/shale ratio is relatively low (say, less than 50%). Even here, many of the sands may be water-bearing owing to cross-fault leakage; production may be obtained from relatively few sands, interspersed with the water-bearing zones, and distributed over a large gross vertical interval.

The fault zone itself may or may not seal. Slivers of sand tend to get caught up in the fault zones on the Niger Delta, allowing vertical leakage of petroleum (Weber et al. 1978). Although destroying fault traps at deeper levels, this leakage may allow a petroleum charge into shallower reservoirs. Other faults off the Niger Delta are sealing because of clay smears along the fault plane (Weber et al. 1978). Smith (1980) has investigated fault seal in the Louisiana Gulf Coast, and found that some faults seal even when sandstones are juxtaposed across the fault zone, as long as the sands are of different ages. This is due to the presence of fault-zone material that has formed as a result of mechanical or chemical processes directly or indirectly related to the faulting. Where parts of the *same* sandstone are juxtaposed, the fault tends *not* to seal. Where sand is juxtaposed against shale, a seal is produced.

At shallow depths (a few hundred m), extensional faults may form open conduits for petroleum; at greater depths, they are likely to be forced closed by overburden pressure. It is reasonable to expect that the likelihood of a fault zone providing a high permeability conduit for petroleum leakage is enhanced: (i) at shallow depths, (ii) in tensional settings, (iii) during periods of fault movement, and (iv) where reservoirs are overpressured. At depth and in active compressional settings, fault zones are very unlikely to provide a pathway for petroleum migration. In the absence of well-understood local circumstances, it is best for the practicing petroleum geologist to evaluate a fault trap on the basis of the juxtaposed lithology alone, that is, assuming the fault zone allows lateral but not vertical migration.

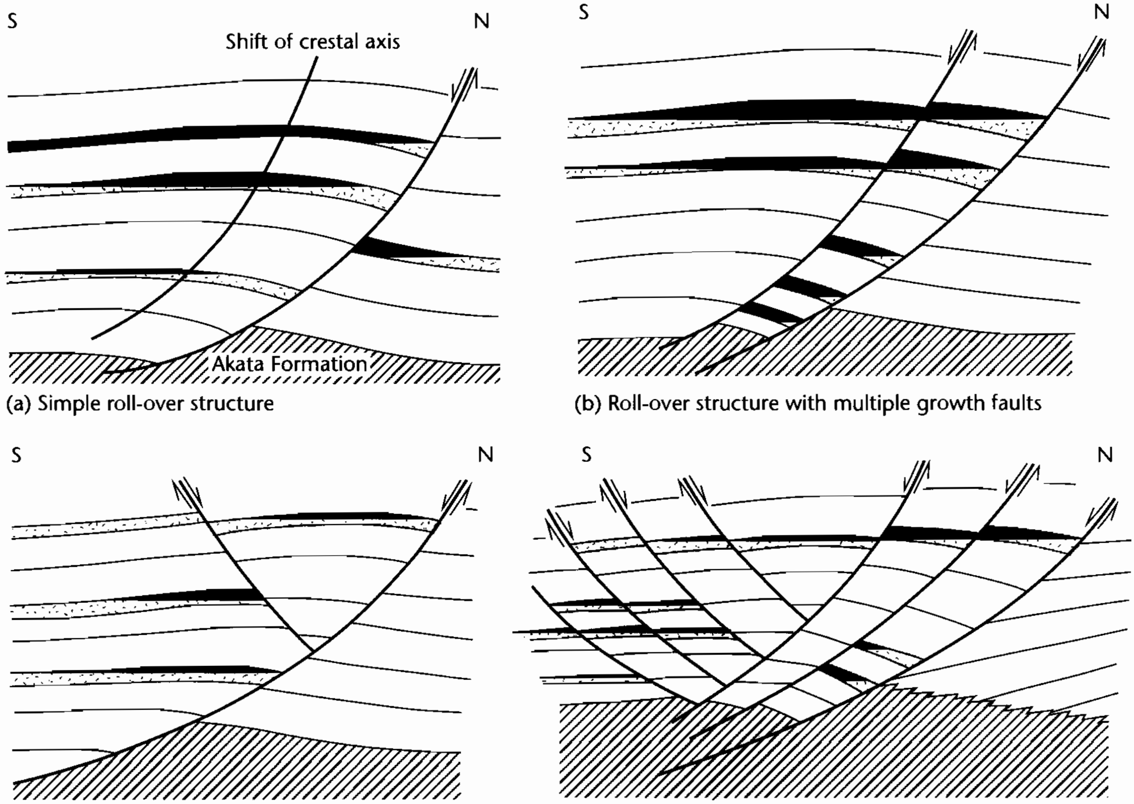


Fig. 10.59 Varieties of roll-over structure forming petroleum traps in the Niger Delta area (after Weber et al. 1978). Only a few reservoir sands are shown in the schematic sections and the sand thickness has been enlarged.

A further trap that may form as a result of gravitational processes is the *ramp anticline* at the front of *gravitational thrust sheets*. When sheets of detached sediment slide downslope, they may pile up at local obstructions, forming contractional anticlinal features. These occur particularly on deep water delta slopes.

Compactional structures

The most important trap type formed by compactional processes is the drape anticline (Fig. 10.60), caused by differential compaction. The presence of a basement horst (effectively noncompactible) causes significant thickness variations in the overlying highly compactible sediments. As these compact, drape features are formed because the absolute amount of compaction is greatest where the sediment is thickest.

If the area above the horst remains elevated relative to surrounding areas, shallower water sedimentary facies may develop that are less compactible than the surrounding muds. This will exaggerate the differential compaction. The sedimentary facies and diagenetic history of the reservoir unit may be quite different over the crest of the drape anticline than off its flanks.

Drape anticlines form a very successful trap type. They are frequently simple features formed without tectonic disturbance (unless basement faults are reactivated) and frequently persist over a long period of geological time, from shortly after the time of reservoir deposition through to the present-day. They are therefore available

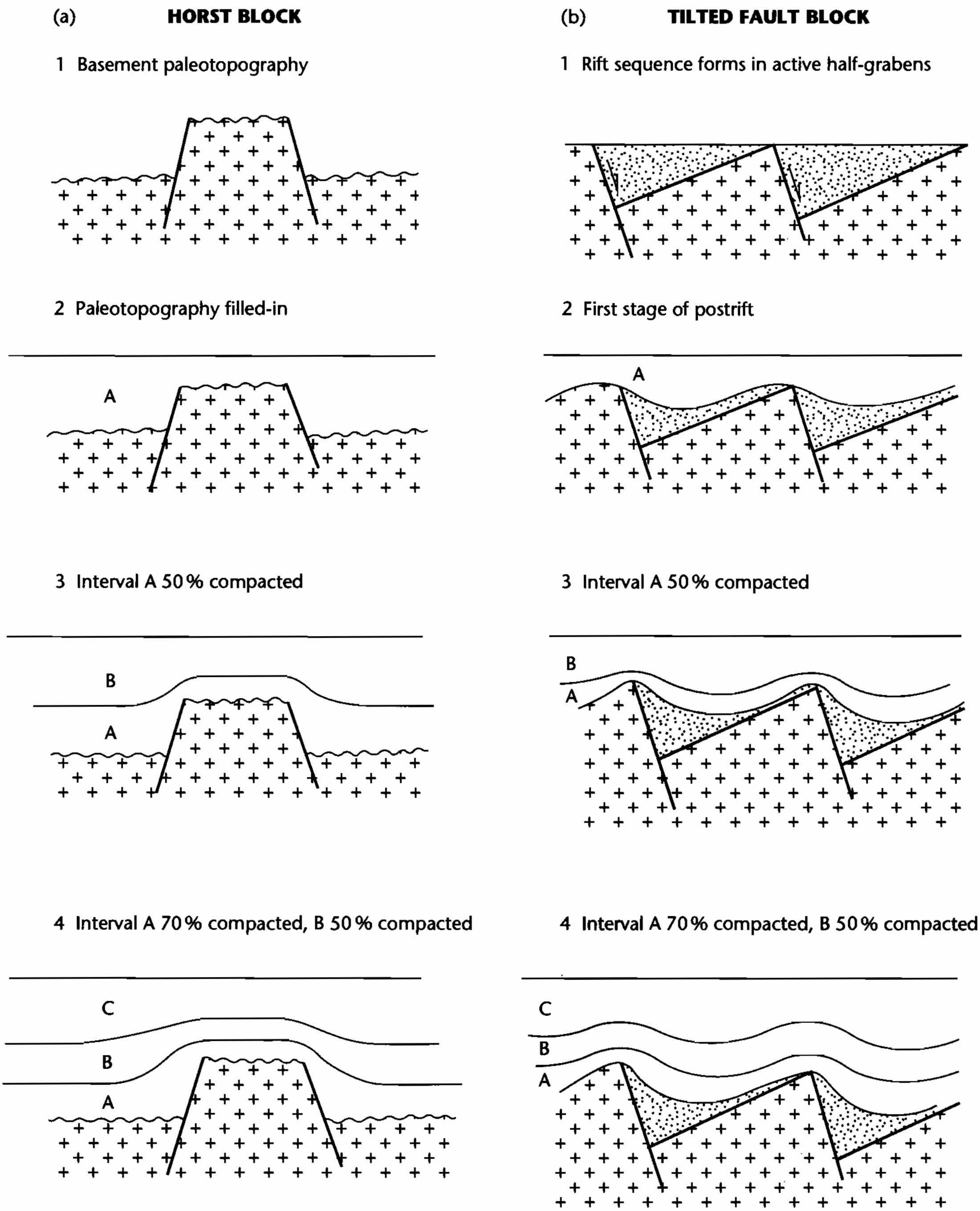


Fig. 10.60 Formation of drape anticline by differential compaction. Relief of anticline increases with depth. Basement topography causes thickness variations in the compactible sediment column. As these sediments compact, drape anticlines are formed.

to trap a petroleum charge over a long time span, and are very forgiving of inaccuracy in estimation of charge timing.

Owing to dependence on the existence of basement topography, drape anticlines commonly form in the passive sedimentary cover to rifted megasequences, particularly over the relatively elevated parts of tilted fault blocks in the prerift (Fig. 10.60b). In these settings, a petroleum charge is frequently needed from synrift or very early postrift source rocks, since the later postrift is commonly devoid of a source. Communication of the reservoir with the source is often, therefore, the critical factor for this play. A second critical factor may also be the presence of a reservoir in the postrift. Since a considerable amount of crustal thinning is the cause of the basement topography that forms the drape anticline, these areas commonly subside rapidly due to thermal contraction, leading to deep water conditions. The only reservoirs present may be deep-sea fans, as in the Lower Tertiary submarine fans of the North Sea.

Examples of drape anticlines are the Forties and Montrose fields of the North Sea, which occur within very large (90 km^2 and 181 km^2 respectively) low relief domal closures at Paleocene level formed by drape over deeper fault blocks. In the Frigg gas field, the present-day closure on the Eocene submarine fan reservoir is due not only to compaction processes but also to the rejuvenation of Jurassic faults controlling the deeper structure, and to original depositional topography on top of the fan (Blair 1975).

DIAPIRIC TRAPS

Diapiric traps result from the movement of salt or overpressured clay. At depths in excess of 600–1000 m, salt is less dense than its overburden, and liable to upward movement through buoyancy. Salt can flow at surprisingly low temperatures and over long periods of geological time. Once a density inversion is present, heterogeneities in either the mother layer of salt or clay, or in the overburden, are sufficient to trigger upward movement. Examples of heterogeneities are lateral changes in thickness, density, viscosity, or temperature. These changes may be essentially depositional or may be imposed as a result of faulting or folding. In extensional faulted zones, diapirs tend to form through buoyancy where overburden load is most reduced in the footwall. The salt rollers of the US Gulf Coast are examples of this triggering mechanism (Fig. 10.61). Faulting may be basement-involved, or thin-skinned, usually soling out in the ductile layer. This layer may also provide a zone of detachment in contractional areas. Differential loading of a salt layer by thick overlying sediments is a powerful triggering mechanism of diapirism in young shallow delta sequences (Fig. 10.62).

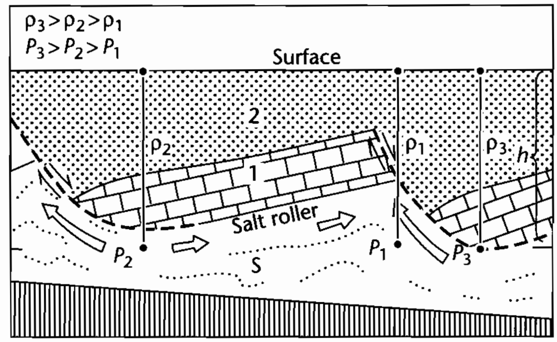


Fig. 10.61 The formation of a salt roller by extensional faulting may trigger the buoyant rise of salt (after Jackson and Galloway 1984). ρ_1, ρ_2 and ρ_3 are sediment column densities, P_1, P_2, and P_3 are pressures at three locations, h is the maximum overburden height (in the hangingwall of the fault) on the top of the salt (S). Overburden pressure is relaxed in the footwall (position P_1) as a result of the extension.

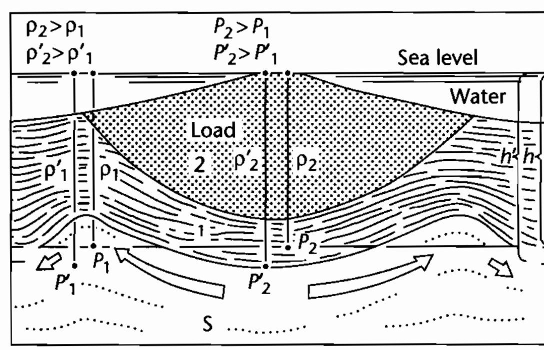


Fig. 10.62 Triggering of salt movement as a result of differential loading by a body of dense sediment. ρ_1, and ρ_2 are the sediment densities prior to movement, exerting pressures P_1 and P_2 at the flank and at the centre of the load respectively. Increased pressure on the salt under the load (P'_2) relative to the pressure at the flank (P'_1) causes lateral and upward displacement towards the lateral diapirs. h and h' are the initial and subsequent depths at which pressures are considered. These conditions commonly occur in young delta sequences (after Jackson and Galloway 1984).

Stages in the growth of salt structures

Salt structures pass through three stages of growth (Fig. 10.63):

- *The pillow stage*, characterized by the thinning of sediments over the crest of the pillow, and thickening into the adjacent *primary peripheral sink*. No piercement or intrusion of the overlying sediments has taken place. Depositional facies are affected by pillow growth, with higher energy facies, perhaps reefs, developing over the crest. Traps formed at this stage are typically broad domes, while sediments that have been channeled into the topographically low peripheral sink may pinch out pillow-wards, forming stratigraphic traps;
- *the diapir stage*, when the salt body pierces the overburden. These structures are known as salt piercement structures. As the pillow withdraws to form the diapir, *secondary peripheral sinks* may develop close to the diapir, and inside the earlier primary peripheral sinks of the pillow stage. *Turtle structures*, representing thick lenses of sediment that accumulated in the primary sinks subsequently tilted during diapir growth may form petroleum traps. Thick clastics may again pinch out onto the flanks of the diapir, forming stratigraphic traps;
- *the postdiapir stage*. As the diapir grows, a point is reached where the underlying reservoir of salt is depleted, and it can only continue to rise by thinning of its lower trunk or by complete detachment from the mother salt. Overhangs commonly develop. The geometry of the salt diapir and surrounding strata beneath an overhang is generally poorly known. This is due to the fact that the area is in a seismic shadow, and is relatively in-

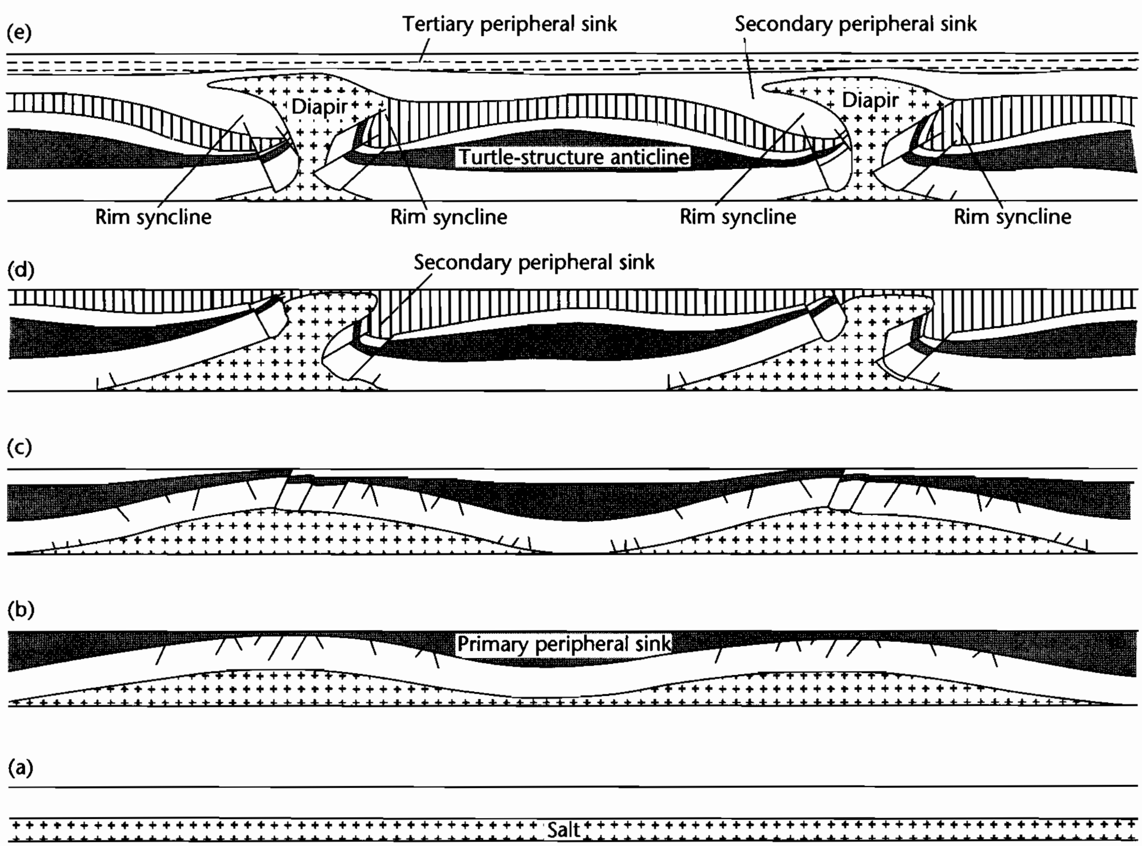


Fig. 10.63 Evolution of salt structures through pillow stage (b) and (c), diapir stage (d), and postdiapir stage (e). Note the lateral migration of peripheral sinks with each stage (from Seni and Jackson 1984). Turtle structures represent the preserved fill of the peripheral sink.

frequently drilled. The typical thickness of a diapir stem is largely unknown. Piercement of salt may take place through to the surface, forming salt domes that are particularly noticeable on Landsat images and aerial photographs, as in north-central Oman.

Trapping potential

Our understanding of the petroleum entrapment possibilities of salt pillows and diapirs has been developed largely through exploration of the Gulf Coast area of the USA. After the Spindletop discovery in 1901, traps associated with salt diapirs became one of the most important and prolific plays in this outstandingly successful hydrocarbon province. The piercement salt diapirs of the Houston Salt Basin were formed by the loading of Jurassic salt with a thick sequence of Mesozoic and Tertiary sediments. Most of the diapirs have intruded to shallow depths, and have created complexly faulted structures. Radial fault patterns are common over the diapir flanks. Reservoirs are commonly broken into a very large number of separate fault compartments. Syndepositional diapir growth caused substantial thickness and facies changes, as well as local erosion. Stratigraphic pinch-out and unconformity traps were formed, and local reef limestone reservoirs developed.

Most production comes from Eocene to Pliocene age sediments overlying and surrounding the salt, and from the diagenetic salt-dome caprock, which directly overlies and is in contact with the salt. The Cap Rock is a calcite deposit with zones of gypsum and anhydrite, formed by the solution of anhydrite-bearing salt by ground waters. Secondary porosity may be very high (>40%), but may be irregularly distributed. The Spindletop (Fig. 10.64) and Sour Lake diapirs have produced 60 to 81 million barrels respectively from Cap Rock reservoirs.

The petroleum trapping possibilities in sediments above and around a mature diapir deposited during its postdiapir stage are shown schematically in Figure 10.65. A variety of further traps, mainly stratigraphic, may develop in the diapir- and pillow-stage sediments (Fig. 10.65). These include structural and combined structural-stratigraphic traps on the crests of turtle structures. A variety of other fault, pinch-out, and unconformity traps are also shown.

In summary, diapiric structures may give rise to a very wide range of petroleum traps of both structural and stratigraphic origin. Although the detection of diapirs on

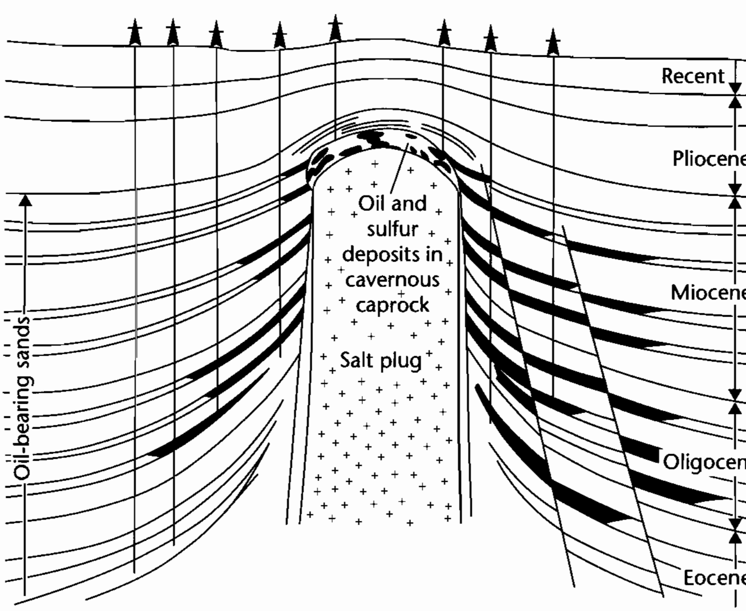


Fig. 10.64 Schematic cross-section through the Spindletop Dome, Texas, showing the distribution of oil reservoirs in both the caprock and on the flanks of the salt plug (after Halbouty 1979).

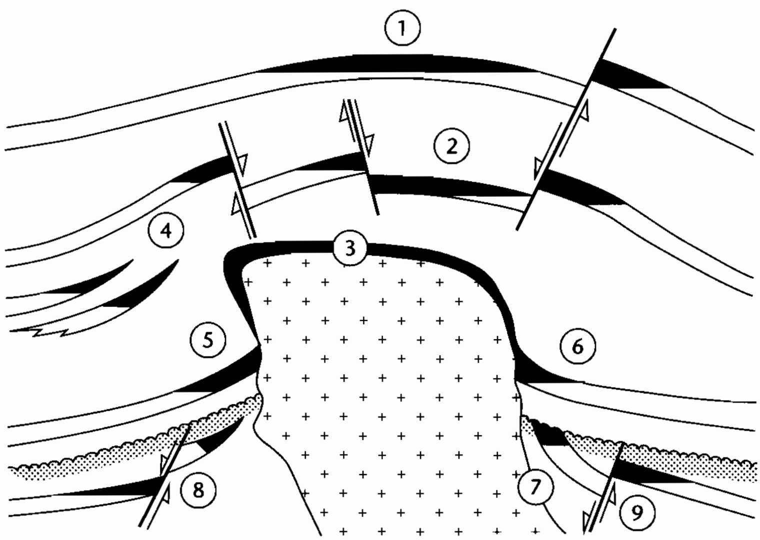


Fig. 10.65 Potential petroleum traps associated with salt diapirs (after Halbouty 1979). A wide variety of stratigraphic and structural traps may develop above and around the diapir, and in its diagenetic caprock. 1, Simple domal trap above the diapir with relatively simple or no associated faulting; 2, Domal trap faulted into graben structures; 3, Diapir caprock reservoir; 4, Stratigraphic up-dip pinch-out caused by facies change into the peripheral sink; 5 and 6, Reservoirs sealed against the diapir wall; 5 is beneath an overhang. 7, Unconformity trap formed by erosion towards the diapir crest; 8 and 9, Fault traps in the flanking area.

seismic sections is not difficult, trap development above and around the diapir is frequently very complex, and individual reservoir units may be quite small, owing to rapid lateral facies changes and complex faulting.

Salt diapirism is likely to occur in quite distinct geological settings. Thick salt deposits may develop in enclosed basins subject to cycles of flooding and desiccation. These may occur in the rift and early postrift stages of continental margin development. Examples are the Jurassic salt of the Gulf Coast and Albian salt of the South Atlantic. The occurrence of salt substantially enhances the petroleum resource potential of these provinces.

Mud diapirism

Mud diapirism is most likely to develop in prodelta clay sequences underneath the thick, rapidly deposited regressive sandy sequences of modern and Tertiary deltas. Examples are the Baram (Borneo), Niger (West Africa), Mississippi (USA), and Mackenzie (Arctic Canada) deltas. Excess pore pressure builds up in these clay sequences because low permeability prevents the expulsion of sufficient pore fluids as the sediment undergoes compaction (§9.2). The overpressure lowers the strength of the sediment and promotes ductile flow.

Although traps associated with salt diapirs have been better studied, the indications are that mud diapir structures offer broadly similar trapping possibilities. Structures may be very complexly faulted, with reservoirs broken into a multitude of separate units. Mud diapirs can be distinguished from salt diapirs on seismic sections on the basis of seismic velocity. Salt has a much higher velocity than overpressured shale. Furthermore, mud diapirs tend to lack the well-developed rim synclines that typically surround salt diapirs. Factors may be the shorter lived process of mud diapirism, and the smaller volume from which mud withdrawal appears to take place (Harding and Lowell 1979).

10.6.2.2 Stratigraphic traps

A stratigraphic trap is primarily caused by some variation in the stratigraphy of the basin-fill. This variation may be essentially inherited from the original depositional characteristics of the fill, or may result from subsequent diagenetic changes to it. The detailed stratigraphic trap classification of Rittenhouse (1972) (modified slightly in Allen and Allen 1990, p. 390) emphasizes the tremendous diversity present amongst stratigraphic traps. Stratigraphic traps may be classified as either *depositional* (in which the trap geometry is related to sedimentary facies changes), related to *unconformity* surfaces (either above or below), or *diagenetic*. Among the diagenetic traps, there are not only those caused by mineral diagenesis such as dolomitization, but also biodegradation of petroleum (tar mats) and phase changes to petroleum gas (gas hydrates) and interstitial water (permafrost).

A large number and wide range of stratigraphic traps have been discovered by over a century of exploration, since the drilling of the first exploration well by Colonel Drake at Titusville, Pennsylvania in 1857. Many of these stratigraphic discoveries, however, have been made by complete accident or at least by incorrect geological reasoning (Halbouty 1982). The giant East Texas field for example, a 5×10^9 barrel unconformity trap, was drilled as an anticlinal trap. The detection of stratigraphic traps requires a high level of geological expertise. Great emphasis must be placed on an understanding of the stratigraphic evolution of the basin, through a detailed sequence-by-sequence analysis. Of particular importance is the understanding of paleogeography and sedimentary facies for each depositional sequence and parasequence.

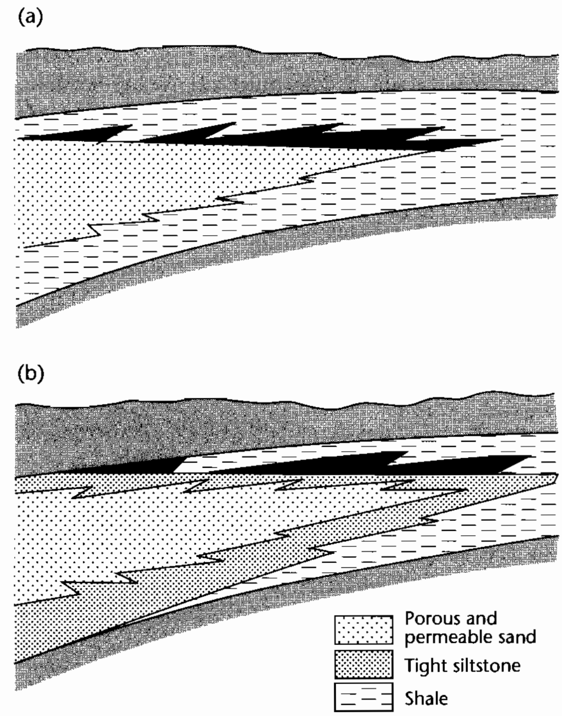


Fig. 10.66 Location of petroleum accumulation in facies change traps. When the change is abrupt (a), the petroleum is trapped in good quality reservoir rock. When the change is gradual (b), the petroleum is trapped in an up-dip "waste zone" of nonreservoir rock (after Downey 1984).

PINCH-OUTS

Whatever the geometry and origin of the entire reservoir unit, any porous facies may pinch out laterally, and, when combined with regional structural dip, may give rise to a stratigraphic pinch-out trap. Such traps were previously described on the flanks of salt diapirs. Pinch-out traps may be extensive and of very low dip. When the depositional pinch-out is gradational, an up-dip transitional "waste-zone" of very poor quality reservoir rock may be present (Fig. 10.66). Much or all of the petroleum charge may leak into the poorly producible waste-zone, forming a noncommercial accumulation. Ideally, the up-dip facies change should be rapid and complete in order for an effective lateral seal to be produced (Downey 1984).

DEPOSITIONAL TRAPS

Traps may develop in a wide range of depositional environments, ranging from eolian dune to submarine fan (§8.5). The selection of just three of the more common depositional traps discussed below are representative of the variability and complexity of depositional traps.

Fluvial channel traps have been described from the Cretaceous basins along the eastern flanks of the Rockies (Selley 1985). An example is the South Glenrock field of the Powder River Basin, Wyoming (Curry and Curry 1972), which clearly shows the meandering channel geometry of the productive sand. The South Glenrock example illustrates two important features of many channel traps: that reservoir sand thicknesses are typically small, limiting the reserves of these accumulations, and that the channel-fill may not be reservoir rock but clay. The geometry of the trap clearly depends on the geometry of the channel. Braided, meandering, anastomosing, delta distributary, and tidal channels would have different geometries. Channels may sometimes be detected as a result of differential compaction relative to the surrounding shales. Some degree of structural closure may be needed to produce the trap (for example, a regional tilt or structural nose). Owing to the isolated nature of channel sands, they may not receive a petroleum charge. It is important, therefore, that source rocks are developed within the same depositional sequence. The effectiveness of a channel trap clearly depends on the lithology into which the channel is incised. Thus, although the channel itself may have a very distinct, sharp, lateral boundary, leakage may occur into the adjoining fluvial sediments.

Clay-filled channels may provide a lateral seal to reservoir sands in the adjacent incised sequence. Examples are present in the Sacramento Valley of California (Garcia 1981), and the Pennsylvanian Minnelusa sandstones of the Powder River Basin, Wyoming (Van West 1972).

Submarine fans may be developed on a very much larger scale, and give rise to large petroleum accumulations. An understanding of the sediment transport system is required for accurate prediction of submarine fans; a sequence-by-sequence basin analysis is particularly critical. We have previously seen that submarine fans tend to be developed at particular stages (lowstands) and locations (base of slope) in the depositional sequence (see especially §8.2).

The Tertiary of the North Sea provides numerous examples of submarine fan reservoirs. The Balder oilfield of the Norwegian sector (Sarg and Skjold 1982) for example is a series of Paleocene-age sand-rich suprafan lobes, with the trap geometry provided by depositional topography and subsequent submarine erosion. A hemipelagic shale caprock seals the suprafan complex. The discovery well was drilled by Esso in 1967 as a test of a structural prospect. The area was reinterpreted in the 1970s using seismostratigraphic principles and the field found to be a stratigraphic lowstand systems tract trap.

Reefs (§8.5.4) may provide high-relief stratigraphic traps. Isolated pinnacle reefs may be completely encased in younger marine shale. Barrier reefs on carbonate shelves generally need to be sealed up-dip by tight back-reef facies. As noted for pinch-out traps, there is a risk that the back-reef facies will constitute a waste zone of nonproductive reservoir rock. Although the relief on many reef traps may be considerable, the size of the accumulation is dependent on the presence or absence of permeable strata that terminate against the reef body. Careful seismostratigraphic analysis may be required to detect these zones of leakage. The distribution of reservoir units within reef complexes may be variable and unpredictable, not only owing to depositional facies changes but also to the effects of diagenesis. Reefs have formed very successful petroleum traps around the world, including in the Devonian of the Western Canada Basin, in the Sirte Basin of Libya, in the Tertiary of the Salawati and North Sumatra Basins of Indonesia, in the Miocene of Sarawak, in the Permian Basin of west Texas, and in southern Mexico and the Arabian Gulf. Sophisticated exploration techniques, primarily in geophysical data acquisition, processing and interpretation, may be needed to explore successfully for reefs in mature provinces. The remaining, smaller reefs in these provinces are extremely subtle features, their detection requiring a very high level of geological and geophysical expertise.

Unconformity traps

A variety of traps may develop at unconformities, both immediately above and immediately below the unconformity surface. Many of the depositional stratigraphic traps previously described may also develop on unconformities. An example is a pinch-out trap. Overstepping marine shales frequently provide a topseal to shallow shelf or shoreline sands. These traps develop on margins undergoing marine onlap, and transgression, typically in the transgressive systems tract.

Supra-unconformity sands may be localized by topography on the unconformity surface. Thus, incised valleys and channels on the Type 1 unconformity surface formed at a relative lowstand may become sand-filled during rising sea level. Valleys developed along the strike of the outcropping preunconformity strata may be the location of the first postunconformity fluvial sediment. In both cases, a stratigraphic trap at the unconformity surface may be formed, particularly if regional structural dip is in a suitable direction.

Traps developed beneath an unconformity by *truncation* of reservoir beds may give rise to giant fields. Examples have been previously described of eroded extensional fault blocks in the East Shetland Basin of the North Sea (e.g., the Brent reservoir in the Statfjord field, Fig. 10.54). A further example is the Fortescue–Halibut field of the Gippsland Basin, Australia. There may be several elements to the closure developed in subunconformity traps, including the topography present at the erosional unconformity, and the structural geometry of the preunconformity beds. Cross-faulting, for example, may provide closure in the strike direction. Topography on the unconformity may have been provided in the first instance by fault scarps.

The lithology of postunconformity sediments is critical to the effectiveness of subunconformity truncation traps. If, for example, a thin marine basal transgressive sand is present above the unconformity, leakage may occur. This sand may be so thin as to be below seismic resolution. Careful seismostratigraphic interpretation and basin analysis is required in order to understand the causes of the unconformity and the evolution of the sequences above and below it, before accurate predictions may be made of sedimentary facies impinging on the unconformity surface. Ideal conditions are created where the unconformity subsides rapidly into deep water depths, perhaps as a result of rapid initial fault-controlled or thermal subsidence, and the topography is passively infilled by deep marine muds. Traps developed at unconformities that have been onlapped by shelf, shoreline, or nonmarine sequences may not be effectively sealed (cf. §10.5.4).

When the subunconformity strata are carbonates, exposure at the surface may have very important implications for reservoir development in the subunconformity trap. The Casablanca field in the Gulf of Valencia, offshore southern Spain, was formed by Miocene faulting, erosion and leaching of a Mesozoic sequence of tight, dense limestones (Watson 1981). The faulting formed the paleotopography and fractured the brittle carbonates, allowing the penetration of meteoric waters and the development of secondary porosity to depths of up to 150 m. The eroded, elongate limestone ridge is overlain by mid-Miocene Alcanar Formation organic-rich marls, which charge and cap the accumulation. A similar example is the Angila field in the Sirte Basin of Libya (Fig. 10.67); in this case it is weathered granite that forms the reservoir in the unconformity trap (Williams 1968).

Probably the two best-known North American examples of unconformity traps are the Prudhoe Bay field in Alaska, and the East Texas field.

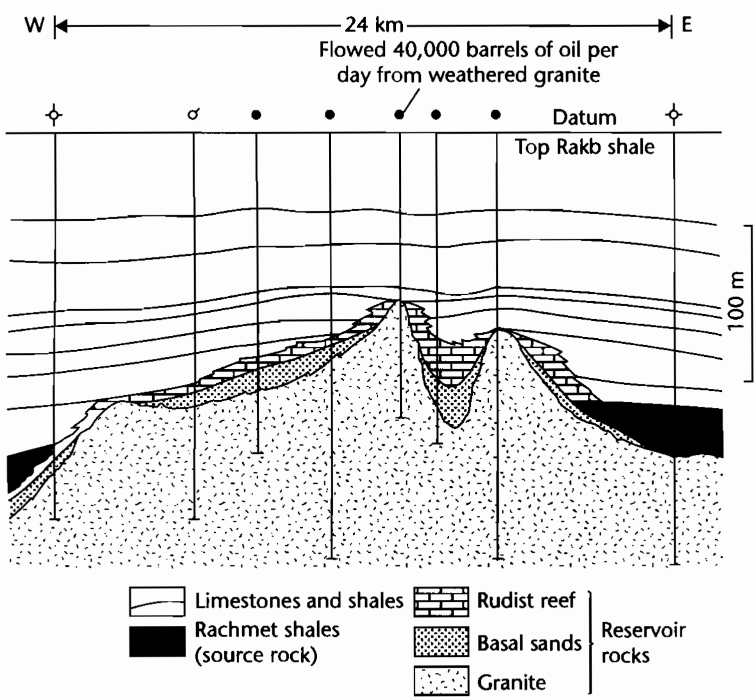


Fig. 10.67 Cross-section through the subunconformity trap of the Angila Field, Libya. Some of the production is from fractured and weathered subunconformity granitic basement (after Williams 1968).

Diagenetic traps

There are a number of traps in which diagenesis has played a significant part. Examples are where cementation (e.g., of dolomite or calcite) has provided an up-dip seal to an accumulation, or where leaching has produced a local reservoir in an otherwise impermeable sequence. These trapping mechanisms are usually established after the main phase of oil generation, and have relatively low predictive importance.

An interesting form of diagenetic trap is where cementation has taken place below the oil–water contact of an existing accumulation (diagenesis is frequently inhibited by the presence of petroleum in the pore space). This may seal in the accumulation despite the subsequent removal of the original trapping mechanism, for example by tectonic activity.

At temperatures of less than about 70 °C, and in the presence of meteoric water, we have seen that bacterial degradation of oil may take place (§10.3.2.5). This can form an impermeable up-dip tar mat that seals subsequently migrated oil. Examples have been quoted from the Californian San Joaquin Valley (Wilhelm 1945) and Russian Volga–Ural region (Vinogradov et al. 1983). Similarly, a change of phase from gas or liquid to solid may also provide an unusual kind of trap. At high latitudes, permafrost may provide an up-dip seal to petroleum accumulations. At particular pressure–temperature conditions (low temperature, high pressure) petroleum gases may form *solid hydrates*. These are solid crystalline precipitates of gas and water. Not only is gas trapped in the hydrates themselves, but may accumulate in reservoirs underlying the zone of hydrate formation (Downey 1984). Hydrates are most likely to form in shallow onshore reservoirs in permafrost areas (examples have been quoted at depths of up to 200 m in Siberia), and in cold, deep sea areas (the Glomar Challenger cored gas hydrates at subsea depths of 600 m on the Blake Plateau).

10.6.2.3 Hydrodynamic traps

Hydrodynamics was briefly introduced in §10.3.2.4 in the context of the movement of petroleum fluids through basins. There are relatively few basins worldwide where hydrodynamics is known to have a significant impact on the entrapment of petroleum. These are typically foreland basins where porous and permeable carrier beds have been uplifted and exposed in adjoining fold–thrust belts, allowing the influx of meteoric water (see §9.6.3). If an outlet for the water is available elsewhere in the "plumbing system" of the basin, hydrodynamic flow of the basin fluids may take place (Hubbert 1953). Once the necessary conditions are known to be established at the basin scale, individual exploration prospects can be evaluated with a view to hydrodynamic effects.

Under conditions of strong hydrodynamic flow, petroleum–water contacts may be inclined rather than horizontal, petroleum may be completely flushed from structural or stratigraphic closures, or hydrodynamic closures may be produced (for example, on structural noses) where there is no other form of closure present. Each prospect needs to be evaluated individually, since prospectivity will depend on a host of regional and local factors that may be difficult to assess.

Clearly, an understanding of the structural and stratigraphic evolution of the basin is required for an assessment of the impact, if any, of hydrodynamic conditions on petroleum entrapment. Generally, however, hydrodynamic traps and hydrodynamic effects appear to be relatively rare.

10.6.3 Timing of trap formation

An understanding of the mechanism of trap formation, and therefore the timing of trap formation, is essential to prospect evaluation. A trap that developed too late to receive a petroleum charge will be filled with pore water. Each of the structural, stratigraphic, and hydrodynamic trap types discussed in this section has implications for trap timing that are obvious. Depositional and unconformity traps are very early, dating from the time the sealing units became effective. Thus these traps are ready to receive a charge from a very early stage. Some structural traps, however, are very late in relation to petroleum charge. Each trap needs to be individually evaluated.

The timing problem is perhaps best illustrated by considering a currently active fold–thrust belt. The fold–thrust belt forms as a result of shortening, at least in the sedimentary cover, which results in uplift. Uplift results in cooling of the overthrust sheets, which switches off petroleum generation. Thus, a timing problem may exist, unless generation is maintained in subthrust positions by loading of the allochthonous sheet, or unless earlier trapped petroleum remigrates into the new fold structures. A similar problem exists for inversion structures. Prior to inversion, migration is usually directed away from the site of the future trap. Inversion may switch off new generation, thus the charge into the inversion trap must be from remigrated oil.

Structures formed in areas of continuous subsidence also need careful evaluation, so that the growth of the structure may be closely related to the timing and volume of petroleum charge. The sedimentary section may need to be backstripped (§9.3) to the time of first trap formation, and the charge system geochemically modeled.