CHAPTER 9

ORIGIN AND MIGRATION OF PETROLEUM: GEOLOGICAL AND PHYSICAL ASPECTS

SUMMARY

(1) Petroleum is a product of the diagenesis of fundamental organic compounds in organic matter that accumulated with fine-grained sediment in a low-energy environment deficient in oxygen.

(2) The energy of petroleum in its source rock is greater than that it will have when it reaches the accumulation. Each path of migration from source to accumulation is a path of continuously decreasing energy during migration. The energy is derived largely from the compaction of the petroleum source rock — usually a mudstone, but some may be fine-grained carbonates.

(3) Petroleum exists as a separate phase by the end of primary migration, from source to a permeable carrier bed. Capillary forces then retard migration, and prevent it when the energy of the migrating petroleum is insufficient.

(4) Primary migration may be stratigraphically upwards or downwards, depending on the direction of decreasing energy. Both normally occur in a compacting mudstone that is intercalated between sandstones or other permeable units. The surface dividing upward and downward migration within the mudstone is a perfect physical and chemical barrier to migration.

(5) Secondary migration is lateral within porous and permeable rock units, generally towards the land of the time. Petroleum accumulates when it arrives in a position in which there is insufficient energy to move it further.

INTRODUCTION

The origin and migration of petroleum have been topics of interest for at least a century, since the early days of the industry, but they are still poorly understood. There are several reasons for this, but the main one is that the processes are too slow to model in the laboratory with confidence, and scaling the model introduces doubts regarding the chemical aspects. Migration through a mudstone is a very slow process because of the low permeability. We can speed this up by taking a material of greater permeability — but the material, and so the chemical composition of it, must be changed. Also, we can accelerate the chemical reactions by heating, but it is not certain that in so doing we get the same reaction as that that would have taken place at a lower temperature, with lower energy, over a longer time. Chemical reactions in the laboratory are subject to cosmic radiation: those in the presumed source rock are subject to gamma radiation from some clay minerals, and we cannot say for certain that this difference is unimportant.

It is impossible at present to distinguish in logic between the generation of petroleum and its primary migration. We believe we can recognize petroleum source rocks from the nature of their organic contents: we can identify petroleum accumulations. No migration path has ever been recognized physically with confidence and reported, so the connection between source and accumulation is *inferred* from analyses of the oil and analyses of the organic content of the supposed source rock, and from geological considerations. It is for this reason that we cannot claim to *understand* the origin and migration of petroleum. At best, we can construct plausible hypotheses.

There is another, less creditable, cause of difficulty: the widespread misunderstanding of the physics of fluid movement through porous rocks. Perhaps the commonest error is the assertion that water moves from high pressure to low pressure. Geologists holding this view cannot defend their position because there are artesian basins in which the water is *demonstrably* flowing from low pressures near the intake area to higher pressures in the aquifer at depth. This misconception has bred others, particularly the widely held view that petroleum migration is always upwards (stratigraphically or absolutely). Downward migration over parts of the migration path is not a new concept, nor one that depends on mathematical arguments: King (1899, p. 80 and fig. 9, and p. 99 fig. 14) clearly understood the movement of ground water without the use of mathematical formulation. Others have postulated downward movement in ground-water and petroleum contexts, notably Versluys (1919), Hedberg (1926) and Hubbert (1940).

The growth of petroleum geochemistry over the last decade or so has been spectacular, and the conclusions reached have been widely accepted. It is not easy for geologists to assess geochemical hypotheses because of their general lack of familiarity with chemical arguments. By the same token, it is not easy for chemists to follow geological arguments. There are books, of course, and all can read; but understanding also requires *doing*, because it is in practising our science that we acquire a feel for it.

For these reasons, we shall take the topic of origin and migration of petroleum in three parts. First, the hydrodynamic aspects will be considered with the geological because this is the physical context of petroleum migration, and they put some constraints on the geochemical hypotheses. We shall then consider the geochemical aspects, finishing with a discussion of the whole topic. The only matter that we shall accept uncritically is that petroleum has its origin in organic matter that accumulated with fine-grained sediment in a low-energy environment deficient in oxygen.

HYDRODYNAMIC ASPECTS OF MIGRATION

We have already seen in earlier chapters that fluids, if they move, move from positions of greater energy or potential to positions of lesser energy or potential. Movement involves loss of energy. It is therefore axiomatic that: (1) *the energy of petroleum in its source rock is greater than that it will have when it reaches the accumulation; and* (2) *each path of petroleum migration from source to accumulation is one of continuously decreasing energy during migration.*

These axioms are independent of any hypothesis concerning the nature and state of petroleum during migration. If any part of the total migration path involves transport in solution in water, then the paths of water migration are, of course, those of petroleum migration and the same constraints apply to both water and the petroleum. In any part of the migration that takes place as a separate phase from water, the path of petroleum migration may diverge from that of the associated water, and capillary forces may act in such a way that migration of one phase may be prevented or retarded by the other. But no situation can arise in which either phase can move to a position in which it will have greater energy.

The commonest source rock is considered to be a mudstone. It must be recognized that a mudstone will rarely be entirely source rock: the source will naturally be part of a mudstone. If the physiographic environment of a sand was not favourable for the preservation of organic matter, it is unlikely that the contiguous mudstone facies was favourable for its preservation because that would involve the coincidence of physical and chemical criteria. The concept of diachronous rock units suggests that at any moment of time during the accumulation of a sequence of mudstones and sandstone, for example, some areas accumulate mud and others sand; and part of the area of mud accumulation may also accumulate and preserve a significant organic content (Fig. 9-1). There will then be a source facies within the mudstone facies that will be both laterally and vertically discontinuous.

As this mudstone subsides, and more sediment accumulates on top of it, it

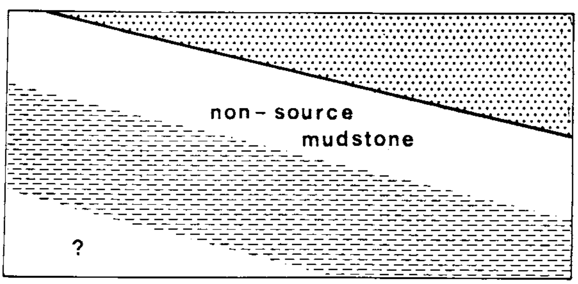


Fig. 9-1. Source rock is a *facies* that is not contiguous with the sandstone facies. (Sandstone, dots; source mudstones, dashes.) View as map or section.

tends to compact. Because compaction can only take place if the pore fluids can be compressed or expelled, a potential gradient is generated in the fluids in the mudstone. When compaction is due to gravity, the direction of this gradient is essentially vertical — upwards and/or downwards to the nearest permeable bed in which the pore fluids are at a smaller potential. If the mudstone is underlain and overlain by such beds, pore fluids in the mudstone will tend to move both upwards and downwards during compaction (Fig. 9-2). There will be a physical surface of maximum potential near the middle of the mudstone that separates the upward tendency from the downward tendency to flow. *This surface is both a hydraulic and a chemical insulator:* no fluid can move across it. If the petroleum source rock is above this insulating surface, any products of organic diagenesis that can move will move upwards towards the overlying bed. If the source rock is below this surface, any products that can move will move downwards towards the underlying bed. If the source rock straddles the surface, movable products of diagenesis will move towards both overlying and underlying beds. And if, as seems likely, petroleum generation involves a net increase in volume, it will also increase pore pressures and the potential gradients. Within a mudstone, this will tend to shift the insulating surface *into* the zone of generation, and so divide it (at least temporarily) into upward and downward zones of migration.

The rate at which the products of organic diagenesis move depends on their state (gas, liquid, or in solution in water), on the potential gradient, and on the effective permeability of the mudstone to that fluid. Those products of organic diagenesis that are taken into solution in the pore water will migrate

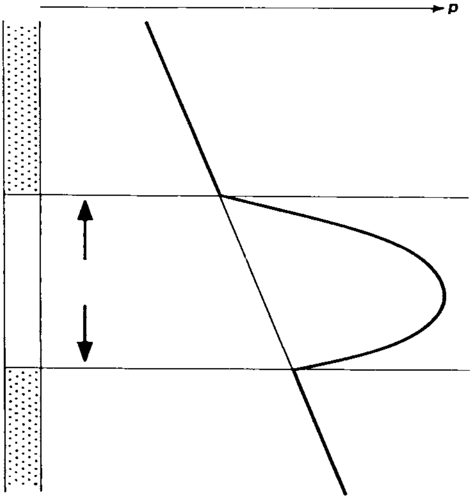


Fig. 9-2. Pressure-depth diagram of upward and downward migration of pore water from compacting mudstone to underlying and overlying sandstones at normal hydrostatic pressures.

at approximately the same rate as the water. Theoretical studies by Bredehoeft and Hanshaw (1968) and Smith (1971) have indicated that during subsidence the abnormal fluid potential in thick mudstones can be maintained for geologically significant periods of time, and that the rates of fluid flow are very slow indeed. Those products of diagenesis that exist as a separate phase will move more slowly because of relative permeability and capillary influences. Products with large molecules may be retained in the mudstone.

We shall postpone consideration of the state of petroleum during primary migration to the next chapter, where chemical aspects will be discussed; but whatever the state may be during most of its primary migration, it is very likely that it exists as a separate phase before primary migration is complete. The main reason for this belief is that the carrier bed is relatively inert chemically, compared with mudstones, and the path to the accumulation may be short.

When petroleum exists as a separate phase in water, two factors affect its migration: water saturations and capillary pressure. It seems certain that the flow of two immiscible fluids in mudstone is similar in principle to such flow in more permeable lithologies. There will be some critical water saturation above which the petroleum can only exist as discrete globules in the pore spaces, and that this petroleum is then virtually immobile. There will also be some irreducible water saturation at which the water is immobile, but at which the effective permeability to petroleum is close to the intrinsic permeability of the mudstone. Such a state does not mean that the petroleum flows: for that, the capillary displacement or injection pressure required for the continuous petroleum phase to move must be less than that existing in the petroleum phase.

Once the continuous petroleum phase reaches the porous and permeable carrier bed, the capillary displacement pressure in the latter is very much less and, as Hubbert (1953, p. 1979) showed, the imbalance of capillary pressure at each end of the volume occupied by petroleum is sufficient to expel it (Fig. 9-3). At the water saturation likely for such a continuous petroleum phase, the effective permeability to petroleum will be relatively large.

The problem of the continuity of petroleum as a separate phase in water is an intriguing one of some interest. We are faced with seemingly incompatible alternatives. When the water saturation is so high that petroleum can only exist as discrete droplets in the pores, the effective permeability to petroleum is zero and it cannot migrate. Within the zone of generation, organic matter is evidently disseminated, so the petroleum generated will also be disseminated. Petroleum must be added to these droplets, or water removed, so increasing the petroleum saturation and decreasing the water saturation (drainage) until a continuous phase is reached. Water will be removed by compaction, so it seems that petroleum disseminated in the pores will only be a transient condition. For petroleum migration in mudstone, the petroleum must either be in solution or in a continuous phase at or close to the irreducible

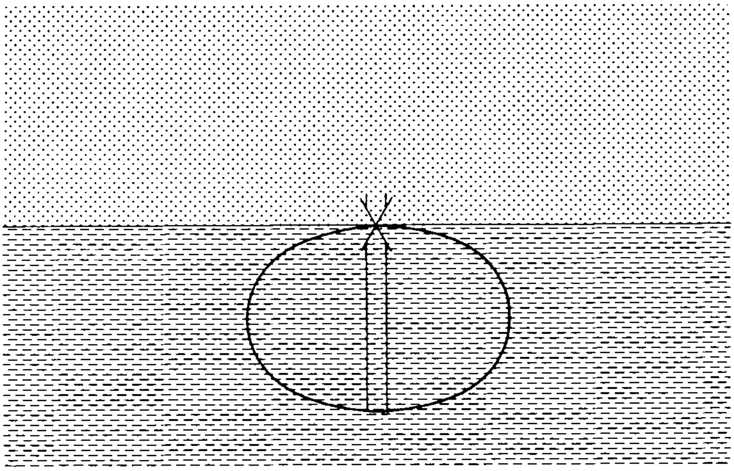


Fig. 9-3. Capillary pressure alone can expel a globule of oil from a mudstone into a sandstone once its interface reaches the sandstone. (After Hubbert, 1953, p. 1978, fig. 14.)

water saturation, at which the effective permeability to water is very small or zero, but the effective permeability to petroleum close to the intrinsic permeability. Migration of petroleum in solution may require less work than that as a separate phase, but the whole migration path must be considered. If we are correct in assuming that petroleum exists as a separate phase before primary migration is complete, then that part becomes virtually impermeable to water, impeding water movement from "upstream" (Chapman, 1972; Hedberg, 1974).

Primary migration takes place in a more rigorous chemical environment than secondary migration, and during it, the fluids are subjected to more severe physical changes. In this connection, upward migration must be distinguished from downward migration. Upward migration above the insulating surface may take all fluids from relatively high pressures to relatively low on expulsion into the overlying carrier bed (the exact amount depending on the rate of upward movement in a subsiding and compacting mudstone). Downward migration into an underlying carrier bed may involve little or no pressure change. Upward migration may involve little temperature change, while downward migration will be to higher temperatures. These influences will be amenable to analysis when we can identify with confidence the source rocks of petroleum accumulations, and so compare the crude oils and gases that have migrated upwards with those that have migrated downwards.

Petroleum migrating as a separate phase almost certainly comes into contact with mineral grain surfaces, or is separated from them by a very thin film of adsorbed water, as it does in the reservoir when the water saturation is sufficiently low. Several common clay minerals are known petroleum catalysts, and it is unlikely that a significant film of water separates the two effectively in the mudstone during primary migration.

Indirect evidence of petroleum as a separate phase during primary migration is given by abnormal pressures and abnormally high resistivities in parts of mudstones in some areas (such as the Bakken Shale of the Williston basin, U.S.A., reported by Meissner, 1978).

We visualize primary migration ending and secondary migration beginning over a large area of the interface between the mudstone that contains the petroleum source rock and the carrier bed.

Secondary migration

In spite of the fact that no secondary migration paths have been recognized with confidence and reported, the conceptual difficulties are not as great as those with primary migration. In the first place, we have petroleum seepages in many parts of the world; and secondly, when we put an oil well onto production, oil demonstrably flows through the reservoir to the well. The main difficulty concerns the role of water movement, so we shall begin with a discussion of secondary migration in an aquifer in which the water is at rest. We shall also simplify the discussion by assuming oil migration in an isotopic, homogeneous, granular, water-wet carrier bed; and regard oil as incompressible, without gas in solution. The principles apply to gas.

Movement in the final stages of primary migration seems to require the petroleum to be in a continuous phase through the pore space, so it is inferred that it remains as a continuous phase initially (at least) in the carrier bed.

Considering upward migration from the mudstone interface first, there is some critical vertical dimension to the oil that will enable it to move upwards under the force of gravity (buoyancy) against the resisting forces, chiefly capillarity. The upward pressure due to buoyancy increases relative to the ambient water pressure by $(\rho - \rho_o)g$ per unit of elevation above the carrier bed interface from which the oil is emerging. Hobson (1954, p. 73) and others have estimated this critical vertical dimension to be of the order of a few metres at most in typical carrier and reservoir rocks.

We can measure the capillary displacement pressure required to move the oil front from one set of pores to the next, so the critical dimension can be estimated from:

$$\Delta h_o = p_i/(\rho - \rho_o)\,g. \tag{9.1}$$

If we take 10 kPa (1.5 psi) as being a representative maximum carrier bed displacement pressure, and 200 kg m^{-3} as a representative difference of oil and water mass densities, then:

$$\Delta h_o = 10^4/(200 \times 9.8) = 5 \text{ m}.$$

The oil being less dense than the water, the macroscopic water/oil interface is mechanically unstable. As the oil is forced out of the mudstone over a wide area, the water/oil interface will become wavy, with a tendency for "diapiric" oil bodies to form; and the amplitudes of those near the dominant wavelength (see p. 332) will be amplified at the expense of the others (Fig. 9-4). As soon as one oil "diapir" reaches its critical vertical dimension, it will move and tend to drain others. This oil will move vertically upwards, in static water, until it reaches the cap rock.

The criterion with any change of lithology encountered during this vertical migration, and there may be several within real carrier beds, is that the capillary displacement pressure required for further progress must be less than that existing in the oil. Vertical migration ceases as soon as the pressure in the oil is insufficient to overcome the capillary resistance. The cap rock is a fine-grained material of which the capillary displacement pressure exceeds – and usually exceeds by a wide margin — that existing in the oil. The oil is then diverted along this lithological interface, in the direction of decreasing energy, in the up-dip direction literally and strictly.

When the oil is diverted along the base of the cap rock, the situation is comparable with that at the termination of primary migration from an overlying source rock, but not identical to it. The criterion for up-dip migration is the same as before: the difference of vertical elevation within the continuous oil phase must exceed the critical vertical dimension.

For migration downward from an overlying source rock, there is no mechanical instability at the oil/water interface, and the critical vertical dimension depends on the relief of the cap-rock/carrier-bed interface. For source rocks sufficiently rich to generate enough oil to form a commercial accumulation, the critical vertical dimension must be achieved sooner or later, unless the source rock is directly over the trap.

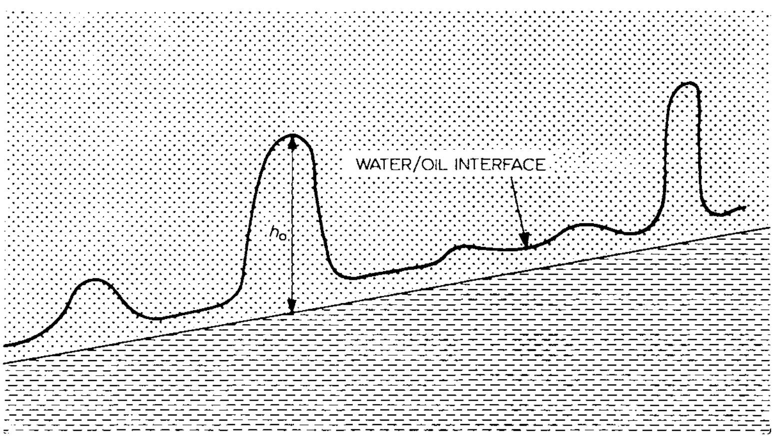


Fig. 9-4. "Diapiric" water/oil interface at the beginning of secondary migration at the bottom of the carrier bed.

Secondary migration up-dip follows a path, or paths, of local minimum potential — much as rivers do — and migration continues until the oil arrives in a position of minimum potential with respect to the physical constraints of the cap rock. Here it accumulates. The quantity that can accumulate depends on the volume of this space of minimum potential, and on the quantities of oil generated. If the space of minimum potential becomes entirely filled with oil, further secondary migration to it will result in overflow from the *spill point*, which is a local position of minimum potential with respect to the accumulation, and so the process will continue until the oil either reaches another space of minimum potential or dissipates at the surface.

The rate of migration of the oil depends not only on the vertical dimension, the physical properties of the oil, and the lithology of the carrier bed, but also on the relative permeability to oil, which is a function of the water saturation (Fig. 9-5).

We noted on p. 168 that experimental curves of relative permeability show a hysteresis effect, depending on whether the initial water saturation was zero or one. The advancing oil front is an injection of oil into 100% water saturation. This part, therefore, corresponds to drainage — from a practical point of view, the drainage curve for water saturations less than the critical oil saturation required for a continuous oil phase. In this part of the relative permeability curves, the relative permeability to oil is very small, and that to water, quite high. We infer, therefore, that much of the pore water is displaced at the oil front so that the water saturation within the migration oil column is such that the relative permeabilities are at least better balanced ($s_w \simeq 0.6$–0.7).

If there is a "tail" or retreating oil front at the lower end, this corresponds to imbibition, and the water saturation increases here at least to the critical saturation at which continuity of the oil phase is lost. The relative perme-

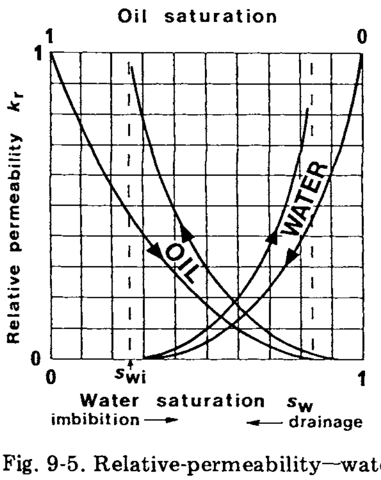


Fig. 9-5. Relative-permeability—water saturation diagram.

ability to oil at the tail is probably less than it is at the head, so there may be a tendency for the oil stream to attenuate. Any oil left behind as a discontinuous phase will be swept up by the next front. All fronts (if there are more than one) will follow the paths of local minimum potential energy on the upper surface of the carrier bed (like an inverted river drainage system), so progress towards the trap will tend to bring migration paths together, and the accumulation will be fed by one or more streams of oil. A detailed contour map of the top of the carrrier bed would indicate the possible paths.

Natural carrier beds are rarely homogeneous or isotropic, so we must consider briefly the main effects of heterogeneity and anisotropy on migration paths.

When two immiscible liquids occupy a single pore, the pressure in the wetting liquid is slightly less than that in the non-wetting liquid, and the non-wetting liquid occupies the position that minimizes its potential energy. The difference of pressure across the liquid/liquid interface is the capillary pressure. We are not concerned here with isolated drops of oil in pores, but with a continuous network of oil through the pore space in a definite volume of the carrier bed. We are concerned, therefore, with the macroscopic upper water/oil interface.

The magnitude of the capillary displacement pressure is a function of the radii of curvature of this interface within each pore along the macroscopic interface, such that the smaller the radius of curvature the greater the capillary displacement pressure. The radii of curvature in the smaller pores are less than those in the larger pores, and the capillary displacement pressures required for displacement through the smaller pores are greater than those for the larger pores. The migrating oil occupies the larger pores preferentially, because these are the paths of least work.

Heterogeneities and anisotropy in carrier beds are generally related to bedding, and so affect the upward migration of oil across the bedding. Migration across a graded carrier bed in which the grain size, and so the pore size, increases upwards is facilitated by the decreasing capillary displacement pressure required and the increasing pressure available within the oil. If the oil is a bubble that is large compared to a single pore, the imbalance of capillary pressure at the leading and trailing surfaces impels the bubble upwards. Grading in the opposite sense retards migration. Beds of alternating fine and coarse grain that are not horizontal lead to refraction of the migration path up-dip (Hubbert, 1953, p. 1972, fig. 10). In the coarser beds, the flow path will tend to deviate up-dip: in the finer, more vertical.

Similarly, the lateral migration will also be along paths of least resistance, favouring the larger pores and perhaps by-passing the smaller.

The water in which petroleum migrates will not always be at rest, but also moving along an energy gradient to positions of lower energy.

Migration in moving water

When secondary migration takes place in a carrier bed in which the pore water is in motion, the petroleum migration paths are affected by this motion, and also the geometry of any accumulation. Rich (1921, 1923) clearly understood this, but present understanding is due to Hubbert (1953), who rationalized and quantified the effects. The reader who wishes a more rigorous analytical argument is referred to Hubbert's paper.

When the pore water is at rest, its potential energy is constant throughout the carrier bed: surfaces of equal pressure are horizontal, and the direction of petroleum migration is determined solely by gravity — that is, when unrestrained by cap rock, it is vertical; when constrained by cap rock, it is up dip. When the pore water is in motion, this has the effect of rotating the hor-

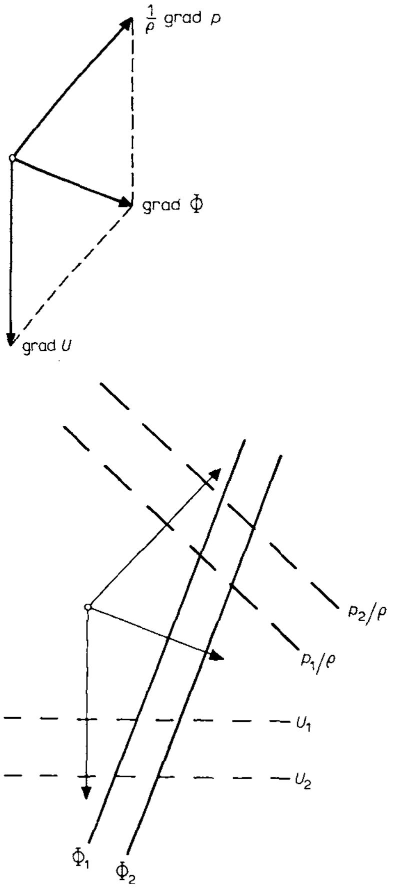


Fig. 9-6. Surfaces of constant pressure, constant gravity potential ($U = gz$), and constant fluid potential (Φ) are normal to their gradient vectors.

izontal reference plane to a plane inclined in the direction of motion, and its normals are similarly rotated, of course, from the vertical. Surfaces of equal potential (the equipotential surfaces) are normal to the direction of motion, surfaces of equal pressure are inclined in the direction of motion, and a component of lateral motion is imparted to migrating petroleum. The magnitude of this component depends on the density difference between the petroleum and the water, in such a way that as the density of the petroleum approaches that of the water, the more nearly do their directions of motion coincide. The direction of gas migration across a carrier bed will be more nearly vertical than that of oil.

The direction of water movement is the resultant of two forces: the force of gravity acting on unit mass of the water, and the force due to pressure acting on unit mass of the water. The resultant is the impelling force acting on unit mass of the water; and, like the others, it has the dimensions of an acceleration (LT^{-2}), and it is the potential gradient (Fig. 9-6).

At any point in the water, *and at any point capable of being occupied by the water*, the water has a potential. When the water is at rest, the potential is constant through the body of water: when the water is in motion, the potential is not constant but decreases in the direction of flow. The water flows in a direction normal to the surfaces of equal potential, which can be mapped through the body of water.

A measure of the water potential at a given point (eq. 8.12, p. 171) is:

$$h = \frac{p}{\rho g} + z \tag{9.2}$$

where h is the total head, $p/\rho g$ is the pressure head, and z is the elevation head (or simply, elevation) of the point relative to an arbitrary datum level (negative downwards).

Oil in the water also has a potential, and it tends to move in a direction normal to its equipotential surfaces. If we consider a small volume of oil migrating, a measure of this potential is:

$$h_o = \frac{p}{\rho_o g} + z \tag{9.3}$$

and since the capillary pressure is a very small part of the pressure in the oil in an aquifer at the depths that we are concerned with, we can take the pressure p to be the ambient water pressure that would exist at that point. Solving eq. 9.2 for p, and substituting it into eq. 9.3, we get:

$$h_o = \frac{\rho}{\rho_o} h - \frac{\rho - \rho_o}{\rho_o} z \tag{9.4}$$

where z is, as before, positive when measured upwards above the arbitrary datum.

Following Hubbert (1953, p. 1991, footnote 3) we divide eq. 9.4 by $(\rho - \rho_o)/\rho_o$:

$$\frac{\rho_o}{\rho - \rho_o} h_o = \frac{\rho}{\rho - \rho_o} h - z. \tag{9.5}$$

Thus, if there is enough data to map h and z, we can map h_o. We shall return to this equation.

Clearly, the projection of the direction of water movement on a horizontal surface is the same as that for oil movement while the oil is migrating without constraint from the cap rock. Both oil and water equipotential surfaces are inclined in the direction of water motion, but by different amounts. If the water flow is directly down-dip, there is some critical dip that equals the "dip" of the oil equipotential surfaces and is normal to the migration path of the oil through the water. A small volume of oil under a cap rock at this critical dip would not move.

Hubbert (1953, pp. 1986—1987) has shown that this critical dip, θ_c, is given by:

$$\tan \theta_c = \frac{\rho}{\rho - \rho_o} \frac{dh}{dx} \tag{9.6}$$

where dh/dx is the slope of the water's potentiometric surface as given, for example, by the contour interval divided by the distance separating two contours on the potentiometric surface (not the hydraulic gradient, in which the length is measured along the aquifer). The coefficient $\rho/(\rho - \rho_o)$ indicates that the heavier the oil, the steeper the slope of the oil's equipotential surfaces and the critical dip. If the oil's density equals that of the water, oil can only accumulate by capillary effects because there is no gravitational effect that will accumulate it.

Gas has a more nearly vertical migration path across a carrier bed by virtue of its smaller density relative to oil and water. The consequences of these effects separately on oil and on gas may well not be the same as the combined effect. If gas alone would take the path G in Fig. 9-7, and oil alone the path O, it is most unlikely that these would be the paths if both were migrating simultaneously. Some intermediate path depending on saturations would be more likely.

Once restrained by the upper surface of the carrier bed, further migration follows paths of local minimum potential. These will not in general be indicated by a detailed contour map of the interface between the cap rock and the carrier bed; but if the contours were drawn relative, not to sea level but to a surface at the critical dip, such a map would indicate the possible paths of migration.

To get an idea of the magnitudes of the critical dip or slope θ_c, consider a potentiometric surface with a slope of 10^{-3}, which is about the steepest regional slope of the Great Artesian basin of Australia. This is a slope of about 3 min of arc. The mass density of most crude oils falls in the range 750—900 kg m^{-3}, so the amplifying factor ranges from four to ten, and the

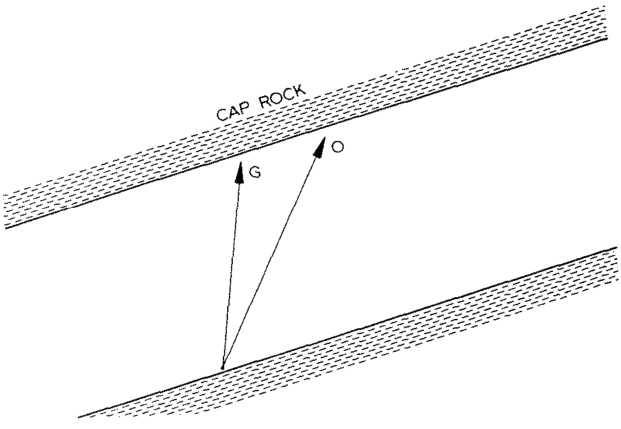


Fig. 9-7. Because of its smaller weight density, gas migration paths are more nearly vertical than oil's under hydrodynamic conditions.

maximum critical slope barely reaches 0.5^0. If we take a potentiometric surface with a slope of 10^{-2}, which exists amongst the oil and gas fields of the south German Molasse basin west of Munich (see Chapman, 1981, p. 102, fig. 5-7), the critical slope varies over the range 2^0—6^0. Locally, greater slopes are possible.

Only in areas of very low structural relief and very large hydraulic gradients or potentiometric slopes will oil and gas migrate other than up-dip qualitatively. If the water is flowing with a component along strike (as it does in the Molasse basin) the oil migration paths will also have a component along strike: the direction of oil migration will be determined by the dip surface relative to the oil's equipotential surfaces, for the oil will migrate along the bedding plane in a direction normal to the line of intersection of the two surfaces. But once a local minimum oil potential has been reached, the migration will be along these axial regions, the plunges of which are usually slight and less than the dips on either side.

Reverting now to eq. 9.5, which we shall simplify by letting $u = h_o\rho_o/(\rho - \rho_o)$ and $v = h\rho/(\rho - \rho_o)$, so that

$$u = v - z \quad \text{(each with dimension of length)}, \tag{9.7}$$

we see that a map of v is a map of the water's potentiometric surface amplified so that it becomes a map of the conceptual surface of critical dip and an oil equipotential surface (Fig. 9-8). Its contours are, of course, also equipotential lines as well as lines of constant elevation on this surface. A map of z on the base of the cap rock is a structural map and its contours are lines of constant elevation. Each intersection of a structural contour with a contour of v is a point on a line of constant u — that is, a line of constant h_o — with its value given by eqs. 9.5 and 9.7 (Fig. 9-9).

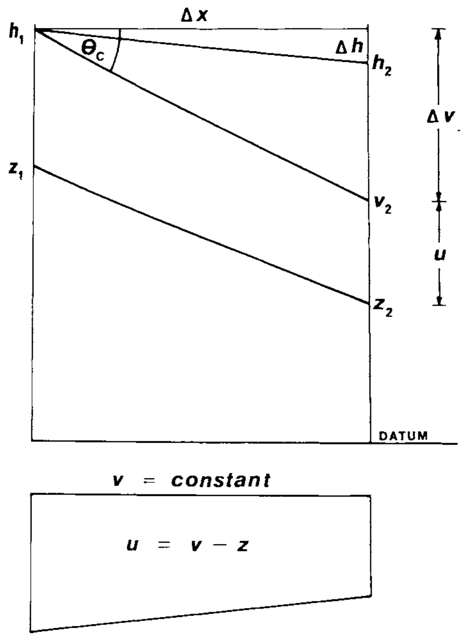


Fig. 9-8. If $\Delta h/\Delta x$ is the slope of the water's potentiometric surface, the slope of the oil's potentiometric surface is obtained by multiplying Δh by the factor $\rho/(\rho - \rho_o)$, the product being Δv. The lower diagram shows the slope of u relative to the oil's equipotential slope.

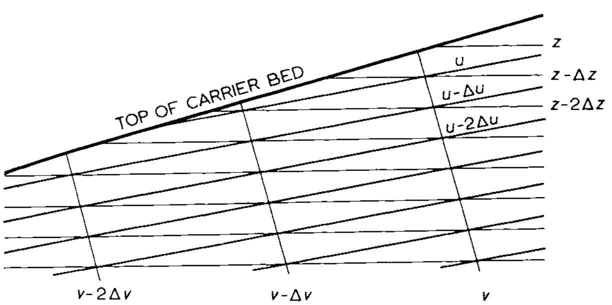


Fig. 9-9. Graphical representation of the interrelationships between surfaces of constant depth (z), u and v, in section.

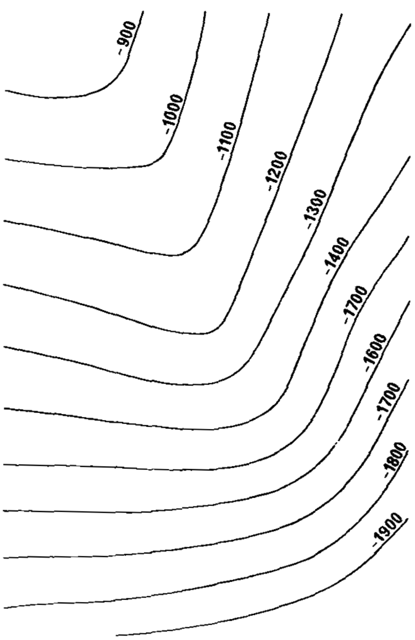
It is convenient at this point to note that when oil accumulates, its oil/water contact is an equipotential surface of the oil and a boundary to water flow. The slope of the oil/water contact is also given by eq. 9.6, so the map of u is not only a map from which possible oil migration paths can be inferred, but also a map of possible oil/water contacts when enclosing spaces of minimum oil potential. The map of u can also be viewed as an isopach map of the interval between an oil equipotential surface and the top of the reservoir rock or carrier bed. Closed contours of low potential are possible areas of accumulation, and the contours are possible oil/water contacts.

If we take the structural contour interval to be 100 m, then υ can be mapped with 100 m contour intervals by choosing Δh so that $\Delta h\rho/(\rho - \rho_o) = 100$ m. Contours constructed from the intersection of the structural contours and the contours of υ are oil equipotential lines on the base of the cap rock, the top of the carrier bed.

Fig. 9-10 is a structure map on the top of a carrier bed, and it shows a nose plunging to the south-east. If the water is at rest, all horizontal surfaces are equipotential and each structural contour coincides with an oil equipotential line at the intersection of an equipotential surface with the top of the carrier bed. Oil would migrate up-dip and accumulate in an area of minimum potential defined by closed equipotential contours. This would be off the map to the north-west. The oil/water contact would be horizontal.

Figure 9-11 is a map of the potentiometric surface of the water in the carrier bed, with a slope of 10^{-2}, indicating flow down the nose to the south-east.

Figure 9-12 is a map of $\upsilon = h\rho/(\rho - \rho_o)$ assuming a mass density such that $\rho_o/\rho = 0.8$, the contour interval being equal to that of the structure map, superimposed on the structure map.



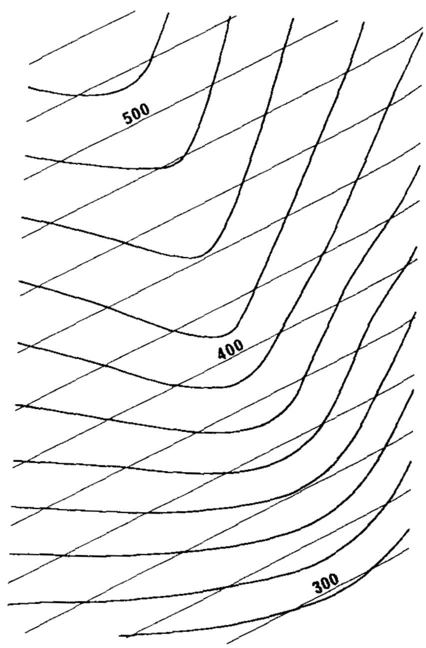


Fig. 9-10. Structure contour map on nose plunging South-East.

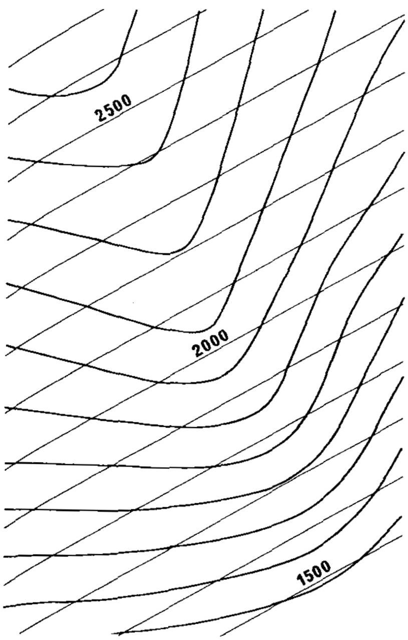
Fig. 9-11. Map of potentiometric surface with slope 10^{-2} superimposed on the contour map of nose (Fig. 9-10).

Figure 9-13 shows the construction of a contour map of u from the intersections of the other two sets of contours. Possible migration paths for oil of relative density 0.8 are shown, normal to the equipotential lines of the oil in the direction of smaller potential. Note that one of these is *down* the axial plunge to an area of minimum potential that is enclosed by oil equipotential lines. These closed contours are possible intersections of the oil/water contact with the top of the reservoir rock, and their contour interval is the same as the structure map. The possible volume of accumulated oil is therefore obtained from a map such as that of Fig. 9-13 in the same way it would be obtained from a structure map if the water were at rest.

Heavier oil would accumulate further down the nose, and Figs. 9-14 and 9-15 show part of the configuration for relative densities of 0.85 and 0.9. These show marked shifts of accumulation due to the density changes, and similar shifts would occur if the water flow were stronger.

Since gas is very much less dense than water, it is not displaced much from the structural culmination. Hubbert (1953) demonstrated that oil can be separated from its gas cap under hydrodynamic conditions.

Another form of hydrodynamic trap has interesting possibilities: that caused by changes in the slope of the potentiometric surface due to changes of thick-



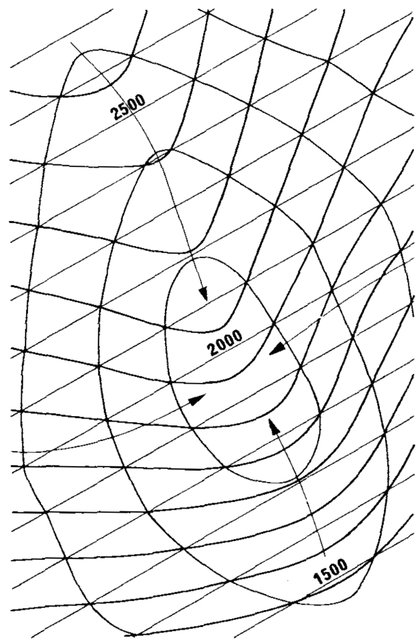


Fig. 9-12. Map of υ for $\rho_o/\rho = 0.8$. This is the potentiometric surface of Fig. 9-11 amplified by the factor 5.

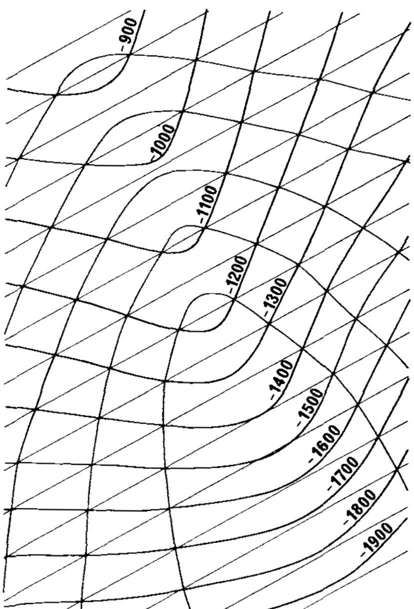
Fig. 9-13. Map of u constructed from Figs. 9-10 and 9-12, showing also possible migration paths for crude oil of relative density 0.8.

ness or of permeability in the aquifer. The hydraulic gradient of an aquifer with constant volumetric rate of flow varies with cross-sectional area and with permeability according to Darcy's law:

$$\Delta h/l = Q/K\,A \tag{9.8}$$

so that if the aquifer thins in the direction of flow, or if the hydraulic conductivity (K) decreases in the direction of flow, the hydraulic gradient, and hence the slope of the potentiometric surface, increases. With down-dip flow, it is possible that this increase in the slope of the potentiometric surface is sufficient to arrest up-dip migration of oil, or to combine with capillary barriers to form an accumulation.

Similarly, when an aquifer is faulted across the flow path with a throw that is less than the thickness of the aquifer, water flow will be impeded and there will be a potential drop across the fault, the amount depending on the permeability of the fault plane and the reduction of area normal to flow at the fault plane (Fig. 9-16). If the dip of the carrier bed/aquifer is greater than the critical hydrodynamic dip, the change in water potential gradient across the fault could act as a hydrodynamic trap irrespective of the permeability of the fault to oil.



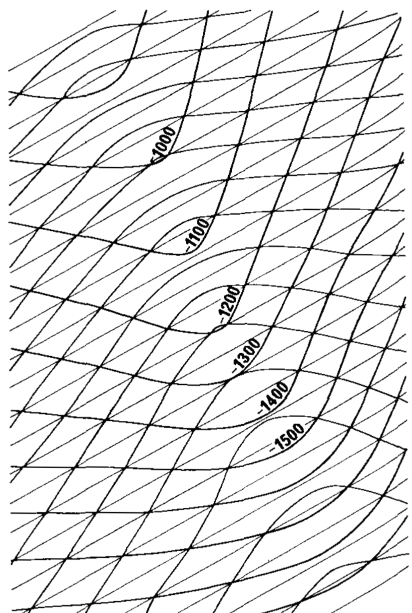


Fig. 9-14. Constructed map of u for $\rho_o/\rho = 0.85$.

Fig. 9-15. Constructed map of u for $\rho_o/\rho = 0.9$.

If the throw of a fault is greater than the thickness of the aquifer, such that a different aquifer is juxtaposed, then the water flow moves to a different stratigraphic level that may have entirely different hydraulic properties (Fig. 9-17). The conservation of matter, assuming negligible compressibility, requires that the volumetric rate of flow, Q, be constant in both aquifers,

$$Q = K_1 A_1 \Delta h_1 / l = K_2 A_2 \Delta h_2 / l \tag{9.9}$$

so the ratio of their hydraulic gradients is given by $K_2 A_2 / K_1 A_1$ where, for practical purposes, the areas are proportional to the thickness. In such a case there may be an abrupt change of slope of the potentiometric surface (and so of the critical hydrodynamic dip) across a fault, as well as a drop of potential.

We rarely have enough data to map such details, but it is worth noting that the appropriate potentiometric map for hydrodynamic conditions may involve several aquifers in faulted regions. By the same token, if petroleum can pass these faults, its migration path may lie through several stratigraphically distinct horizons. All these complications exist in regions of growth faulting, and the hydrodynamics of the water flow due to compaction changes as the faults move.

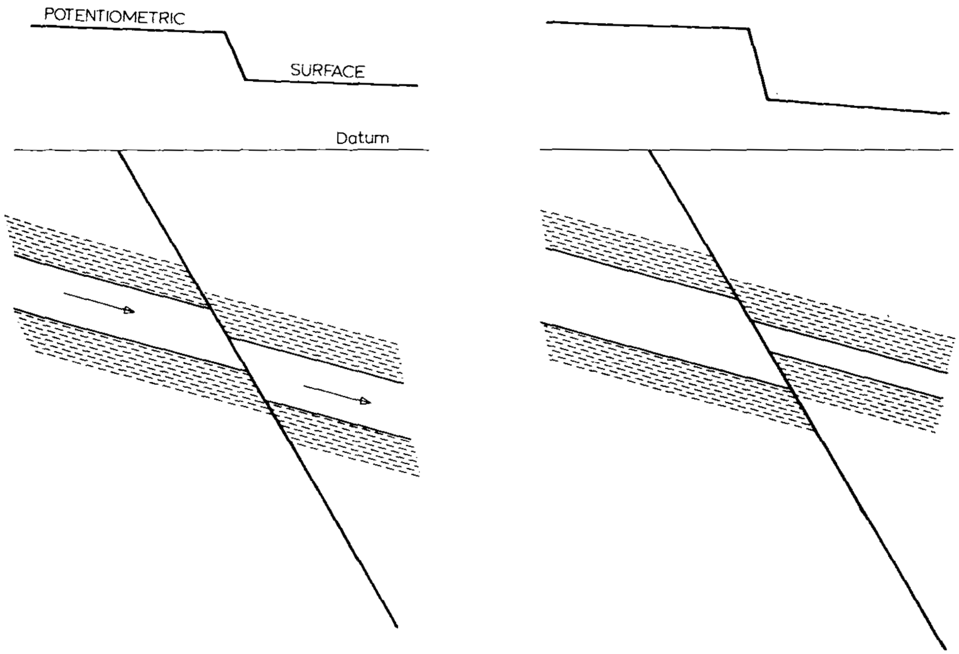


Fig. 9-16. Water flowing through a fault loses energy.

Fig. 9-17. Juxtaposed aquifers will normally have different hydraulic properties.

Discussion of the role of faults in petroleum migration will be postponed to Chapter 11, but the same principles apply to such migration across faults from one block to another: the pressure in the oil at the fault must exceed the injection pressure required to pass the fault. There is evidence that this can happen; but the evidence of fault traps is that faults can seal significant quantities of oil behind them.

It cannot yet be claimed that use of the hydrodynamic approach has led to significant oil discoveries that would not have been found taking the usual hydrostatic approach; but, by the same token, there may be large oil fields waiting to be found in positions that would not be credible under hydrostatic assumptions. Where sufficient data are available, such maps should be drawn because the possible rewards far exceed the labour involved. Furthermore, such maps put some constraints on the directions in which the source rocks of accumulations may lie because they can only lie "upstream" of the possible migration paths.

Of course, such statements are more easily made than justified. They assume that the hydrodynamics of the area has not changed since oil generation, and that the structural relief was much the same. Each area must be judged on its own merits, and it can commonly be assumed that the structural relief was no greater at the time of oil generation and migration.

Rates of secondary migration

We do not have reliable field data from which the rates of migration to individual fields can be determined, but a few sums indicate the order of magnitude required.

A giant oil field with 500 million barrels of recoverable oil has about 1.5×10^9 bbl of oil in place — about 250×10^6 m^3. There are Pliocene/Miocene giants (Halbouty et al., 1970, p. 504, table I), so such quantities cannot take longer than 10—15 m.y. to accumulate. Let us assume that it took one million years to accumulate 250×10^6 m^3, that is, 250 m^3/yr. This is rather less than 0.7 m^3/day, so a single migration path of 1 m^2 cross-sectional area would require a flow of 0.7 m/day, or about 10 μm/s. Migration over a distance of 10 km would involve a transit time of about 40 yrs.

Consider a gas-free crude oil with kinematic viscosity (ν) equal to 6×10^{-6} m^2/s flowing in a carrier bed in which the effective permeability to oil is 100 md (100 μm^2) and the effective porosity is 20%. Assuming that the critical vertical dimension of the oil is exceeded by only one metre, the gradient of total head can be estimated from eq. 9.3 to be about 0.2 in static water for $\rho_o/\rho = 0.8$. So, from Darcy's law:

$$
\begin{aligned}
q_o &= k_o\,(g/\nu)\,\Delta h/l \\
&= 30\ \mu\text{m/s}.
\end{aligned}
$$

The macroscopic velocity through the carrier bed is approximately q/f, that is, about 160 μm/s, or 14 m/day. There are no obvious difficulties in accumulating enough oil for a giant field in a million years — or even a few hundred thousand years.

The rate of primary migration per unit area of interface between mudstone and carrier bed is undoubtedly very slow; but this is probably compensated by the very large areas of such interfaces.

If gas, and gas only, is migrating, the principles are the same except that as gas moves to positions of different pressures and temperatures (usually lower) its volume changes significantly. If gas and oil are migrating together in separate phases, the principles are the same, but the details become very complex because gas can dissolve in oil and water. If oil has gas in solution . . . there are many variations on the theme. Oil is also slightly soluble in water, so any oil left behind in a discontinuous phase will probably be removed eventually in solution in moving water.

Accumulation of petroleum in a trap

When petroleum, trickling along one or more paths of local minimum potential, arrives in the trap and begins to accumulate, migration ends but a new set of physical changes begins:

— Water is displaced downwards from the top of the reservoir.

— The oil/water or gas/water contact is displaced downwards.

— The pressure in the petroleum increases while petroleum accumulates.

— The petroleum in the accumulation continues to move in response to these changes.

Migrating petroleum has negligible kinetic energy, so the newly-arrived petroleum is added to the accumulation at the interface, without penetration into the accumulation (much as cream poured into a jug, rather than milk). The water contact will be rather lower near the point of entry. Due to the density difference between oil and water, and gas and water, the potential energy of the accumulation will be greater where the water contact is lower, and there will be sympathetic movement within the accumulation in the direction that tends to restore equilibrium.

Within the accumulation, a new physical environment develops. Within the continuous oil phase, the pressure decreases with elevation above the oil/water contact according to the relationship:

$$\Delta p/\Delta z = \rho_o g. \qquad (9.10)$$

This rate of decrease is less than that in a continuous water phase, so that, if we take their pressures to be equal at the oil/water contact, the oil at any depth within the reservoir above this is at a higher pressure than the water in continous phase with it. This greater pressure is applied to the water, which acquires the pressure gradient $\Delta p_w/\Delta z = \rho_o g$, and so acquires a downward fluid potential gradient. The oil moves upwards, and displaces the water downwards until hydraulic continuity is lost and the water saturation becomes irreducible. At this stage, we infer, the oil comes into contact with the solid surfaces (or a very thin layer of adsorbed water not more than about 1 nm thick) and isolates the pendular rings.

The reasons for this are not clear. Just prior to the acquisition of irreducible water saturation, the effective permeability to water is very small indeed, while the effective permeability to oil approaches the intrinsic permeability. It is possible, therefore, that the steadily increasing reservoir pressure, concomitantly reducing effective stress and increasing porosity (Terzaghi's relationship) proceed at a rate that cannot be matched by water movement. The inferred size of pendular rings suggests small capillary pressures and so early acquisition of irreducible water saturation. Whatever the cause, a significant proportion of the pore space remains filled with water that is apparently immobile. This water is the original water at the time of petroleum accumulation, and may therefore differ in quality from the water subsequently found below the oil/water contact.

Petroleum accumulation may therefore affect the diagenesis of the reservoir rock within the accumulation. A most interesting study of the Gifhorn Trough in Germany (Phillip et al., 1963) revealed that the reservoir sands contained little cement within the accumulations but were well-cemented outside. The authors drew the conclusion that the accumulation of oil inhibited the deposition of cement, and that therefore the oil accumulated before the processes of cementation had proceeded very far. Similar observations led to similar conclusions for some Nigerian accumulations (Lambert-Aikhionbare, 1982), and in Triassic gas sands in the North West Shelf of Australia (Campbell and Smith, 1982).

It must therefore be noted that if porosity, as determined from the sonic or other log, is found to increase upwards across a water contact, this may well be a real effect and not one induced by the pore fluid's influence on the velocity of sound (or the parameter being logged).

ORIGIN AND MIGRATION OF PETROLEUM IN CARBONATE ROCKS

While most commercial accumulations originate from organic matter in fine-grained argillaceous source rocks, some accumulations seem to require a source in marls or limestones. There are no particular difficulties with this. We assume that the physico-chemical requirements for a carbonate source rock are the same as for argillaceous source rocks — the accumulation of organic matter with sediment in an anoxic environment, and its preservation until buried deep enough for the processes of petroleum generation to begin. There would be few field geologists who have not found dark, dense limestones that give off a bituminous smell on fracture.

Carbonates are prone to chemical alteration and solution (rather than mechanical compaction) and the effects of these diagenetic changes on bulk density trends with depth are not clear. Many carbonates appear to suffer no appreciable mechanical compaction because well-preserved, delicate fossils and original structures are commonly found. On the other hand, some marls apparently compact much as mudstones. McCrossan (1961) found that the bulk density of some Devonian marls in Canada increased with $CaCO_3$ content as well as with depth; and the higher the $CaCO_3$ content, the smaller the relative compaction.

One process is evidently solution at grain contacts and recrystallization in pores and voids. This has the same effect as mechanical compaction — reduction of porosity and increase of bulk density — through chemical rather than mechanical transport. Reduction of porosity can only be effected if the pore fluids are commensurately compressed or expelled; and the expulsion of pore fluids from compacting carbonates involves the removal of soluble components. Not only are there no obvious new difficulties in primary migration from carbonate source rocks, but the recrystallization may actually make the process more efficient provided it does not take place before petroleum is generated. The common occurrence of bituminous limestones may indicate early recrystallization that traps the products of organic diagenesis in the rock.

The matter of porosity and permeability in carbonates is much more varied and complex than in sandstones, for there may be two generations of porosity, primary and secondary, or more, and open fractures and joints are much more common than in sandstones. Secondary migration, therefore, may take place in exactly the same way in calcarenites as in sandstones, and accumulation and production from calcarenite reservoirs will also be the same. But fracture porosity in carbonates is more important than it is in sandstones.

Primary porosity in carbonates may be completely destroyed during diagenesis, the recrystallization leading to porosity of a different sort. Vugs may be formed by the solution of fossils, for example, and considerable permeability may be retained in a bed that consists largely of material of very small porosity and negligible permeability. Recrystallization also increases the strength of the material, in particular, its tensile strength, so that fractured carbonate carrier beds and reservoirs are important in some areas. The prolific Asmari Limestone in Iran and Iraq has a matrix porosity of 9—14% on average in Iran, and an intrinsic permeability averaging about 10 md (Hull and Warman, 1970, p. 431) but it is extensively fractured. These fractures are demonstrably open because some wells have very high production rates on very small penetrations of the reservoir, and production changes in one well are relatively rapidly detected in other wells at a considerable distance away in the same reservoir. Hull and Warman note that where sandstones are present, they appear to be unfractured. They also note that there is a regional hydraulic gradient within the Asmari Limestone from the mountains to the Gulf and oil/water contacts on the two flanks of some oil fields differ by as much as 150 m.

The effective drainage areas of wells in carbonate reservoirs with fracture porosity are large, and productivity of wells is usually large. These are important factors in the economics of oil production because the oil can be produced with relatively few wells. High productivity is one of the characteristics of carbonate reservoirs, including reef reservoirs. Intisar field, Libya, for example, tested one well at 74,867 bbl/day (11,900 m^3/day) clean 37° API oil (sp. gr., 0.84) from 223 m (731 ft) of fossil reef (*World Oil*, January 1968).

As regards irreducible water saturations, less is known of carbonate reservoirs than of sandstone reservoirs, and some carbonate reservoirs are thought to be oil-wet. It seems certain, however, that oil and gas will come into close contact with solid carbonate surfaces in the reservoir. In reservoirs with fracture porosity, the irreducible water saturation is probably very low in the fractures, but may be high in the rock itself.

Of particular importance in carbonate provinces is the evidence for differential entrapment of oil and gas. Gussow's (1954) hypothesis of differential entrapment is very simple, and it grew from the observation that in a sequence of reefs in a single trend in the Western Canada basin, the deepest reefs contain gas only; the shallowest, water only; there will be one deep reef with a gas/oil contact, and one shallow one with an oil/water contact, but the others will be full to spill point. Gussow explained this characteristic distribution as follows:

Starting with saturated oil (that is, oil that contains the maximum amount of dissolved gas) migrating up-dip (Fig. 9-18), gas comes out of solution as it moves to lower pressures and temperatures. At the first trap encountered on its migration path, both oil and gas accumulate; but as the trap fills, a gas cap forms by gravity segregation, so when the trap is full, only oil spills out and continues its migration. However, gas can still enter the first trap, displacing oil until the trap is filled with gas only, and filled to the spill point. When this stage is reached, both oil and gas bypass the first trap, and the process is

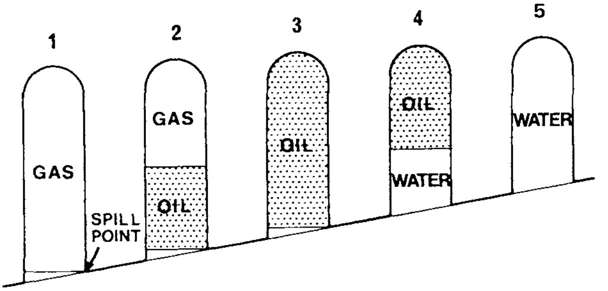


Fig. 9-18. Differential entrapment of oil and gas in traps that are hydraulically connected (Gussow's principle).

repeated at the second trap. When the quantity of gas becomes insufficient to fill a trap, oil with a gas cap is left; and once this trap is full, only oil migrates further and the next trap up-dip contains only oil. When the quantity of oil generated is no longer sufficient to fill a trap, that trap has an oil/water contact, and traps further up-dip will be wet.

Gussow also observed that there is a tendency, not always marked, for the oil to be progressively heavier in traps up-dip. This he attributed to the loss of gas from solution in the oil.

Further subsidence after petroleum generation has largely ceased will result in compression of the accumulated gas, and some may be taken back into solution in the oil, thus raising the water contacts above the spill points. All accumulations in the trend are, of course, hydraulically interconnected, but the water contacts are at different levels depending on the spill points, generally rising up-dip.

A particularly good example of regional differential entrapment is the Silurian pinnacle-reef belt east of Lake Michigan, studied by Gill (1979). This belt is 270 km long and 16—32 km wide (170 by 10—20 miles). Petro-

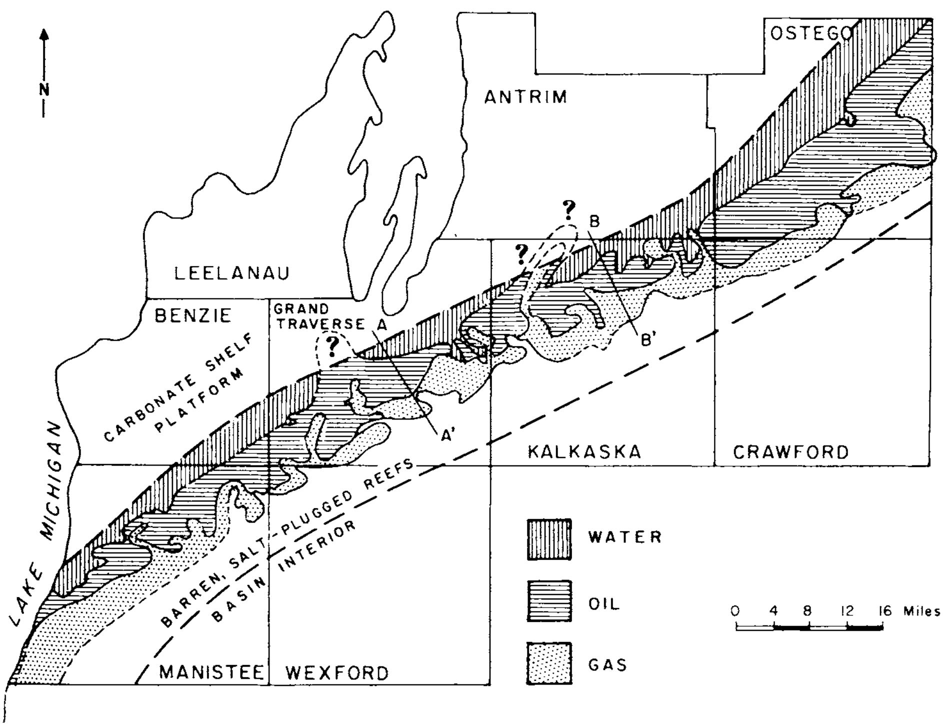


Fig. 9-19. Map of north-western part of Michigan basin showing zones of water, oil and gas accumulations in Silurian reefs. (Reproduced from Gill, 1979, p. 614, fig. 4, with permission.)

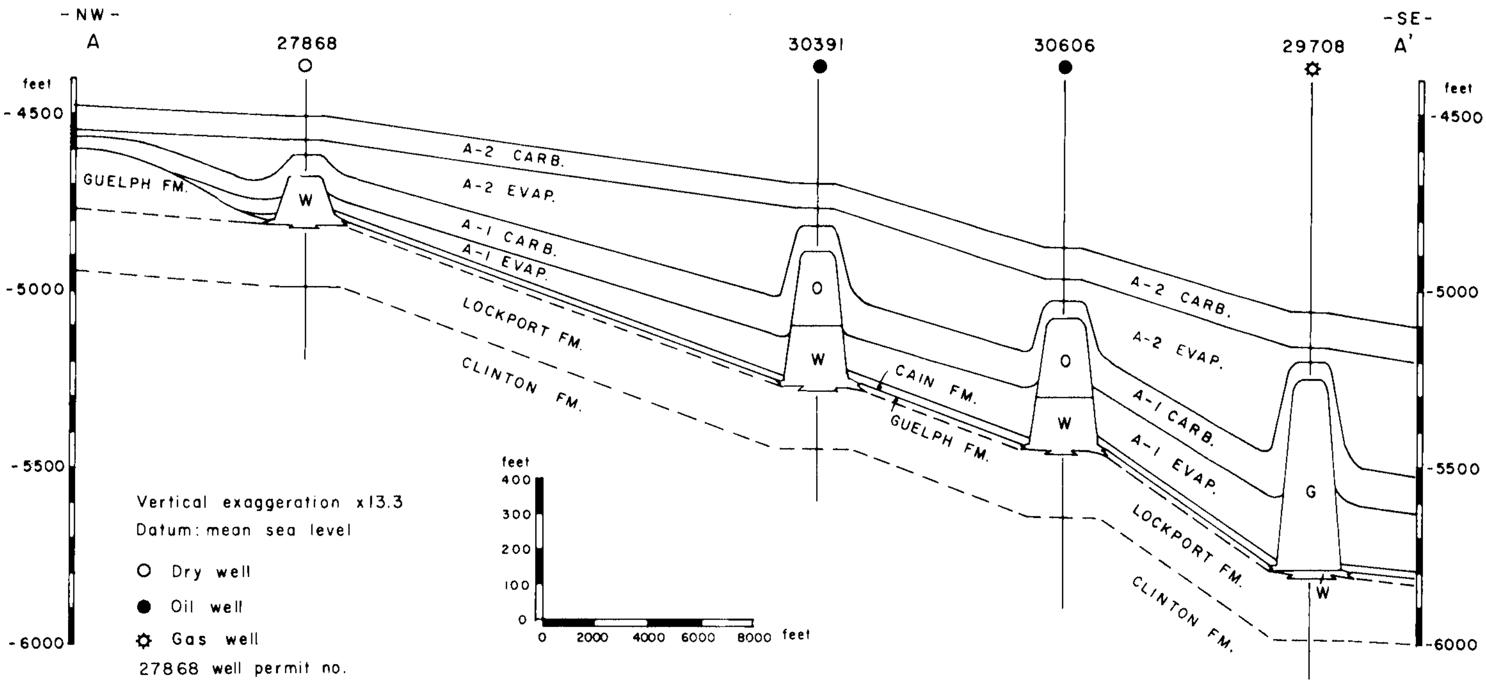


Fig. 9-20. Cross-sections through the reefs of north-western Michigan basin (located in Fig. 9-19). (Reproduced from Gill, 1979, p. 615, fig. 5.)

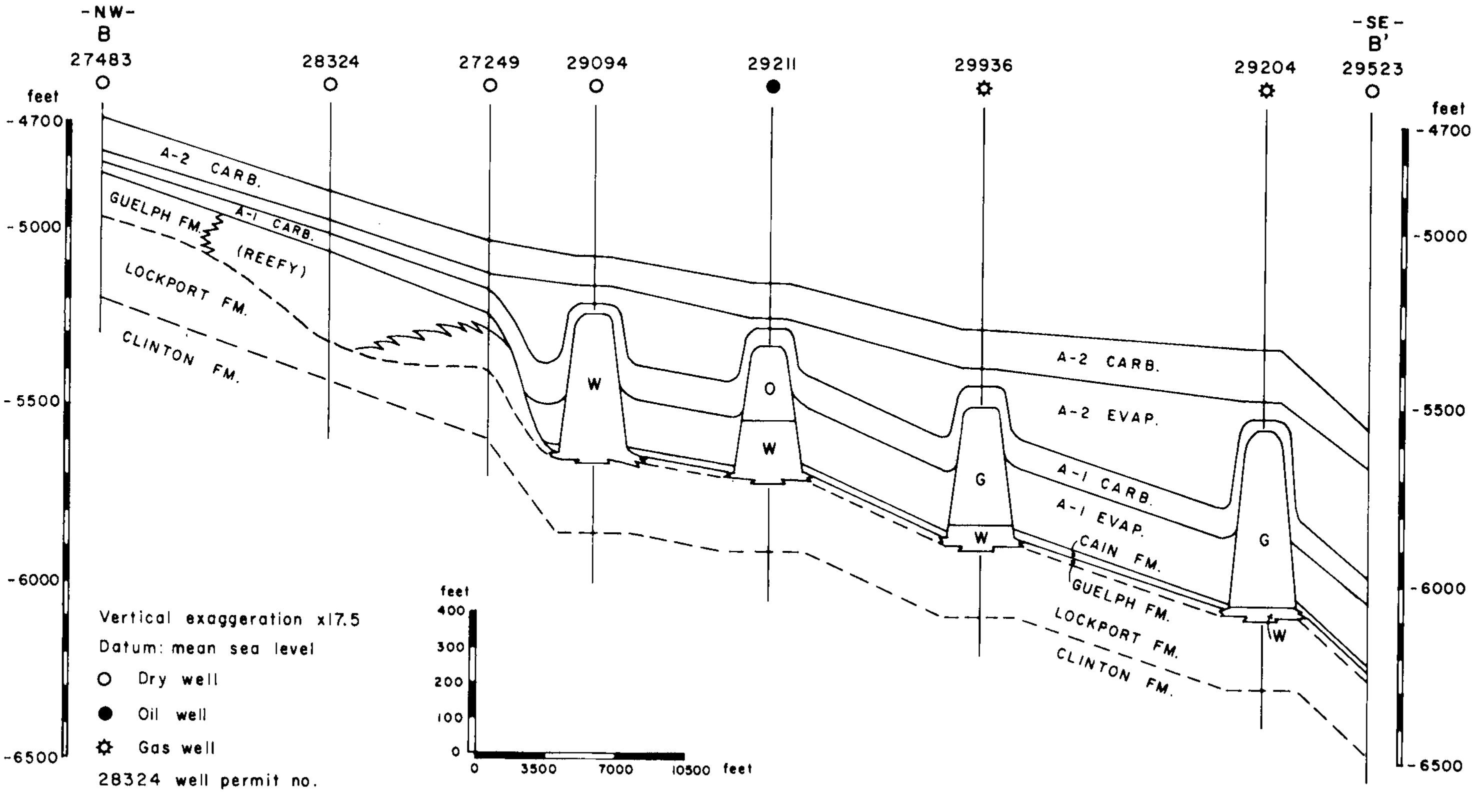


Fig. 9-21. Cross-sections through the reefs of north-western Michigan basin (located in Fig. 9-19). (Reproduced from Gill, 1979, p. 615, fig. 6.)

leum exploration has revealed 432 reefs of which 139 are gas-filled, 221 are oil-filled, and 72 are barren. The cap rock is evaporite. Figure 9-19 shows that the reef belt consists of a down-dip gas zone, an intermediate oil zone, and an up-dip water zone. Figures 9-20 and 9-21 show the cross-sections. The Lockport Formation is the common porous and permeable base to the reefs, and Gill (1979, p. 618) considered that the Cain Formation, *overlying* the Lockport between the reefs and down-dip, is the source rock. The oil gravity increases up-dip from 65^0 to 43^0 API (s.g., 0.72—0.81).

We shall consider these and other reefs in more detail in Chapter 12.

The same processes could, of course, operate in a sequence of sandstone traps; but those in carbonates are clear.

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