OIL EXPLORATION

1977

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3.2 Trap Structure

3.2.1 General

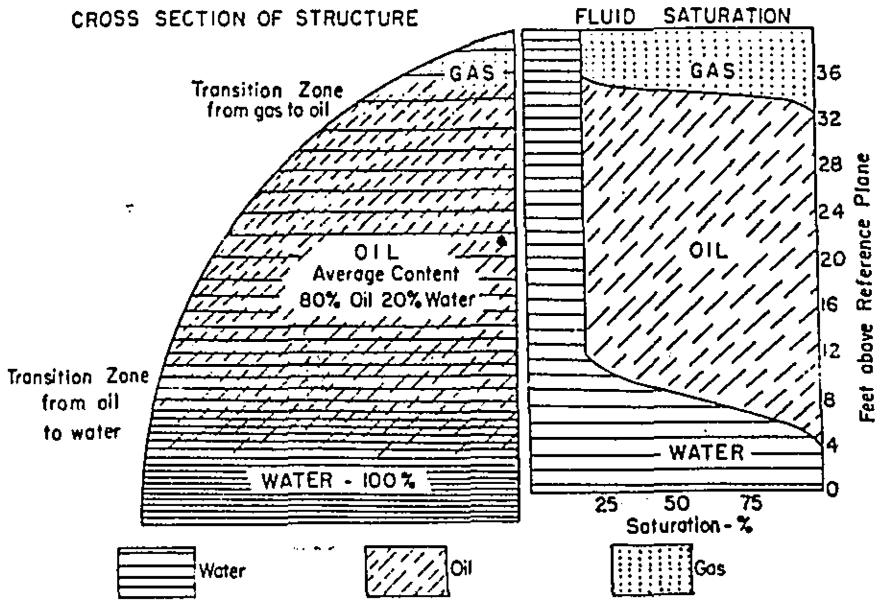
Petroleum reservoir fluids – gas, oil and water – existing in a particular position in permeable reservoir rocks intervening between relatively impermeable lithofacies are a petroleum deposit. Formation of such a deposit requires a structure which can confine fluids and make them accumulate, which is referred to as trap structure.

From the viewpoint of hydromechanics, it may be said as follows: Assuming that the petroleum reservoir fluids are in a state of being able to freely move in reservoir rocks in such a direction as to reduce the potential energy* determined by the internal pressure and the position of the fluids, their particular position, or the position where they are trapped, will be where the potential energy of the existing fluids is minimum and gas and oil with smaller specific gravity will occupy the position.

Assuming that the water phase in reservoir rocks is in a static state, the petroleum trapped position is where the interface between reservoir rocks and relatively impermeable rocks adjacent to the upper or lateral part of reservoir rocks projects upward; in such a case the petroleum-water interface which is an equipotential face, is horizontal. In other words, a form is set up by the geometry of reservoir rocks, buoyancy of petroleum against water, and the volume of petroleum to be accumulated.

Assuming again that the water phase is in a running state, the petroleum-water interface inclines toward the direction water flows. The larger the pressure gradient in that direction and the higher the density of petroleum, the larger becomes the inclination of the interface. Fig. 3.5 illustrates this in a schematic diagram. The gas-water interface is actually almost horizontal since the specific gravity of gas can be disregarded as against that of water.

Fig. 3.4 Distribution of Fluids of Petroleum and Gas Reservoirs in Reservoir Rocks



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* Note: Refer to Section 3.8.3 Migration, accumulation and disappearance of deposits.

When the fluids in a deposit are composed of oil, free gas and edge water in a hydrostatic state, the gas forms a cap above the oil, and both gas-oil interface and oil-water interface are horizontal.

In a hydrodynamic state, depending on the geometry of reservoir rocks and the pressure gradient of water flow, a form out of a, b or c in Fig. 3.6 is taken.

Fig. 3.5 Inclination of an Oil-water Interface in a Hydrodynamic State

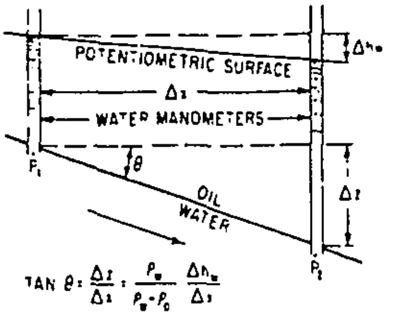


Fig. 3.6 Slippage of an Anticline Trap Position from the Cap in a Hydrodynamic State

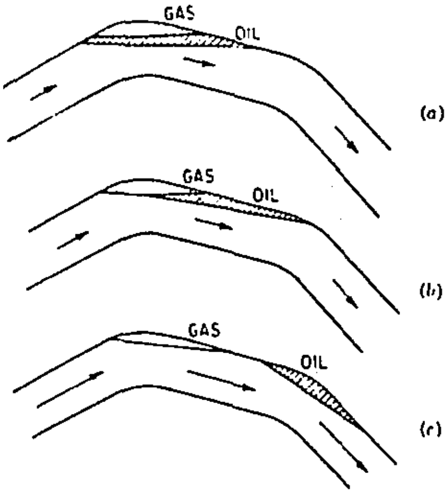
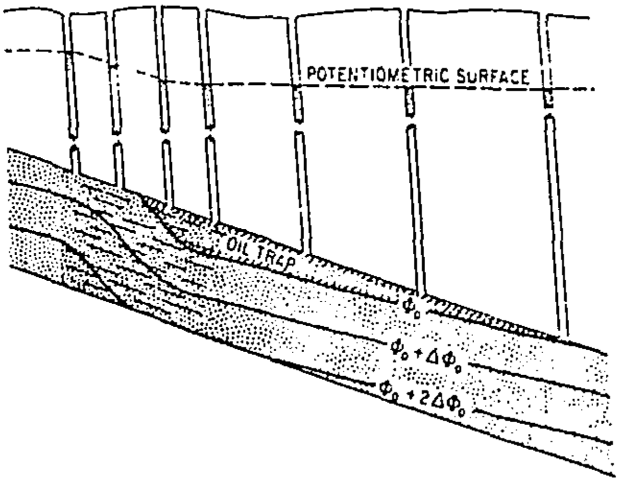


Fig. 3.7 A Trap Caused by a Hydrodynamic State When Difference of Permeability Exists in Monoclinal Reservoir Rocks



The above-mentioned concerns cases where permeability of reservoir rocks is nearly uniform and in an identical direction. If, in a hydrodynamic state, a portion in a reservoir has less permeability compared with both sides of the reservoir as expressed in Fig. 3.7, the equipotential surface is concaved downward in the downstream of such a part, so that an oil trap can be formed in such a reservoir even in case of monocline. Regarding the interpretation based on such potential energies, refer to Section 3.8.3 Migration, accumulation and disappearance of deposits.

3.2.2 Classification of Traps

Traps are first classified generally into three classes: (1) those in a hydrostatic state, (2) those in a hydrodynamic state, and (3) those in a water-unsaturated state.

In class (1), Ⓐ stratigraphic traps, Ⓑ structural traps, and Ⓒ combination stratigraphic-structural traps are typical. In addition to these, there are Ⓓ pseudostratigraphic traps, and Ⓔ aggregated traps in view of the peculiarity of rock salt traps. For the descriptions which follow, refer to Fig. 3.8 and Table 3.3.

Ⓐ Stratigraphic traps principally originate from alteration of lithofacies of contemporaneous sediments. This is further divided as follows: ① normal stratigraphic traps which are formed solely by sedimentation, and ② pseudostratigraphic traps which are primarily caused by sedimentation but can be turned into traps only after tectonic movement has made a reservoir monoclinal.

Ⓑ Structural traps are those formed by tectonic movement (fold and fault). These are further classified into ① anticlines, ② faults, ③ piercement trap, and ④ combinations of anticlines and faults. Anticlines consist only of traps caused by faults in open anticlinal structures (nose structures and terrace structures), while those formed by faults superposed on folds are classified into ④.

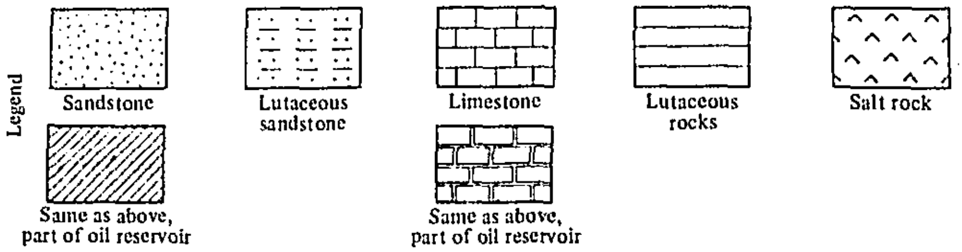
Ⓒ Combination stratigraphic-structural traps are those which can be formed only by a combination of stratigraphic factors and such structural factors as folds or faults.

Ⓓ Pseudostratigraphic traps are apparently the same as Ⓐ - ② - (b) permeability difference traps, but the cause of permeability difference is not related with sedimentation and also the time of occurrence of the cause differs from that of sedimentation.

Ⓔ Aggregated traps, originating from salt domes, are an aggregation of various traps such as Ⓐ - ②, Ⓑ - ①, Ⓑ - ②, Ⓑ - ③, Ⓑ - ④, Ⓒ - ①, Ⓒ - ②, Ⓒ - ③, and Ⓓ - ②.

Fig. 3.8 Kinds of Traps

(Original drawings by Mitsuchi)



Note: The parts enclosed by broken lines in the upper part of each block of model below is formed of impermeable rock (muddy rocks.)

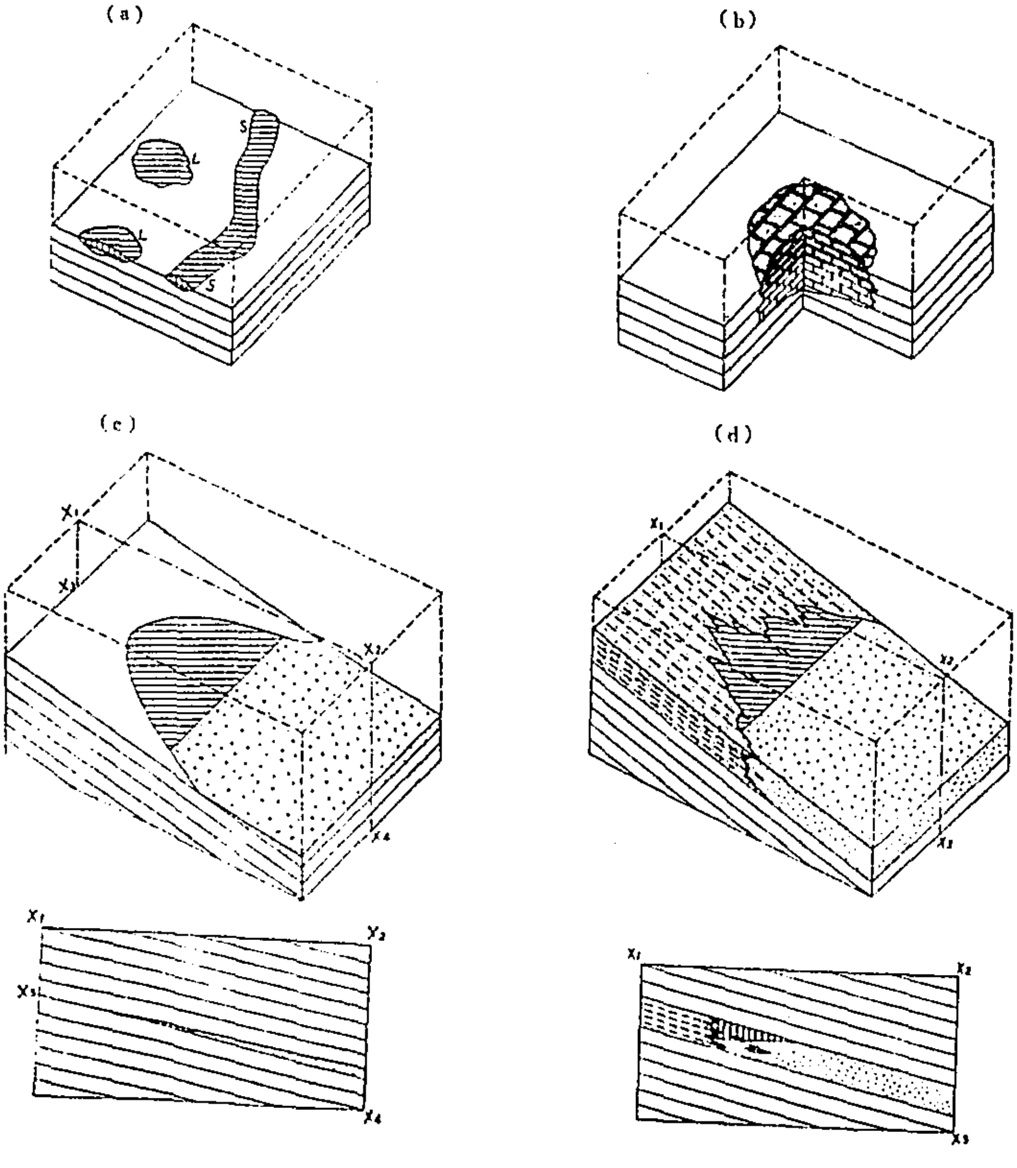


Fig. 3.8 Kinds of Traps (continued)

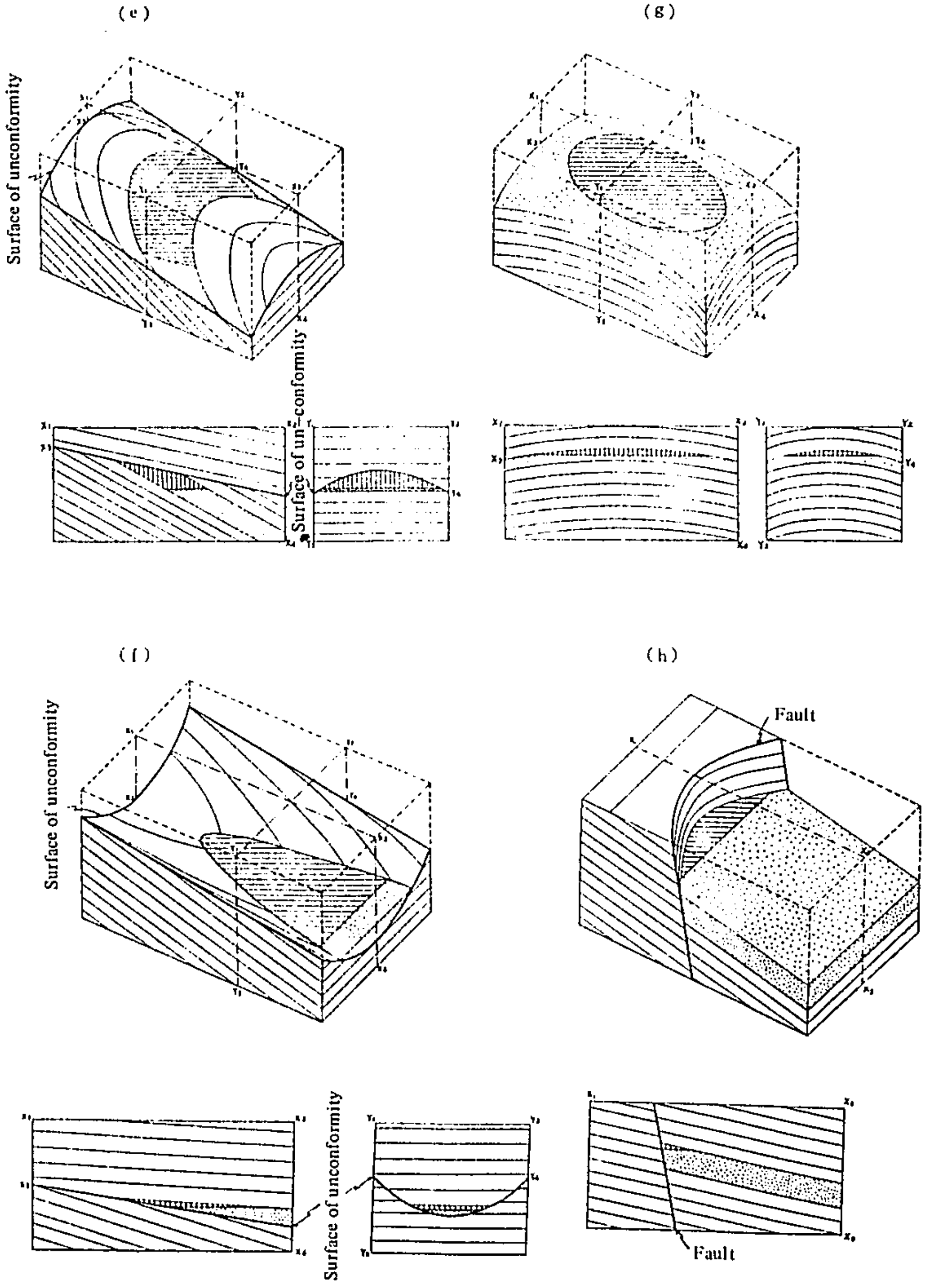


Fig. 3.8 Kinds of Traps (continued)

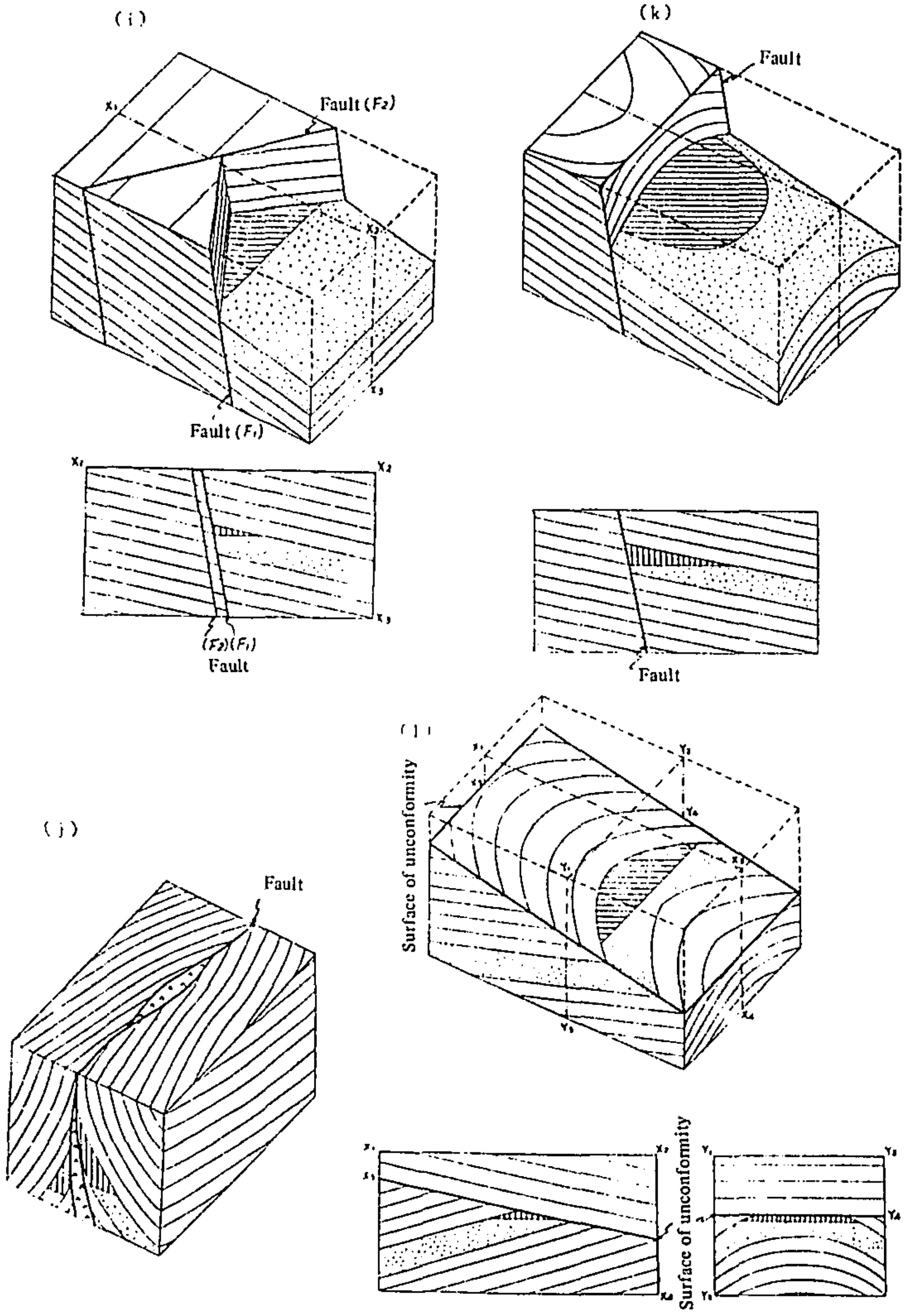
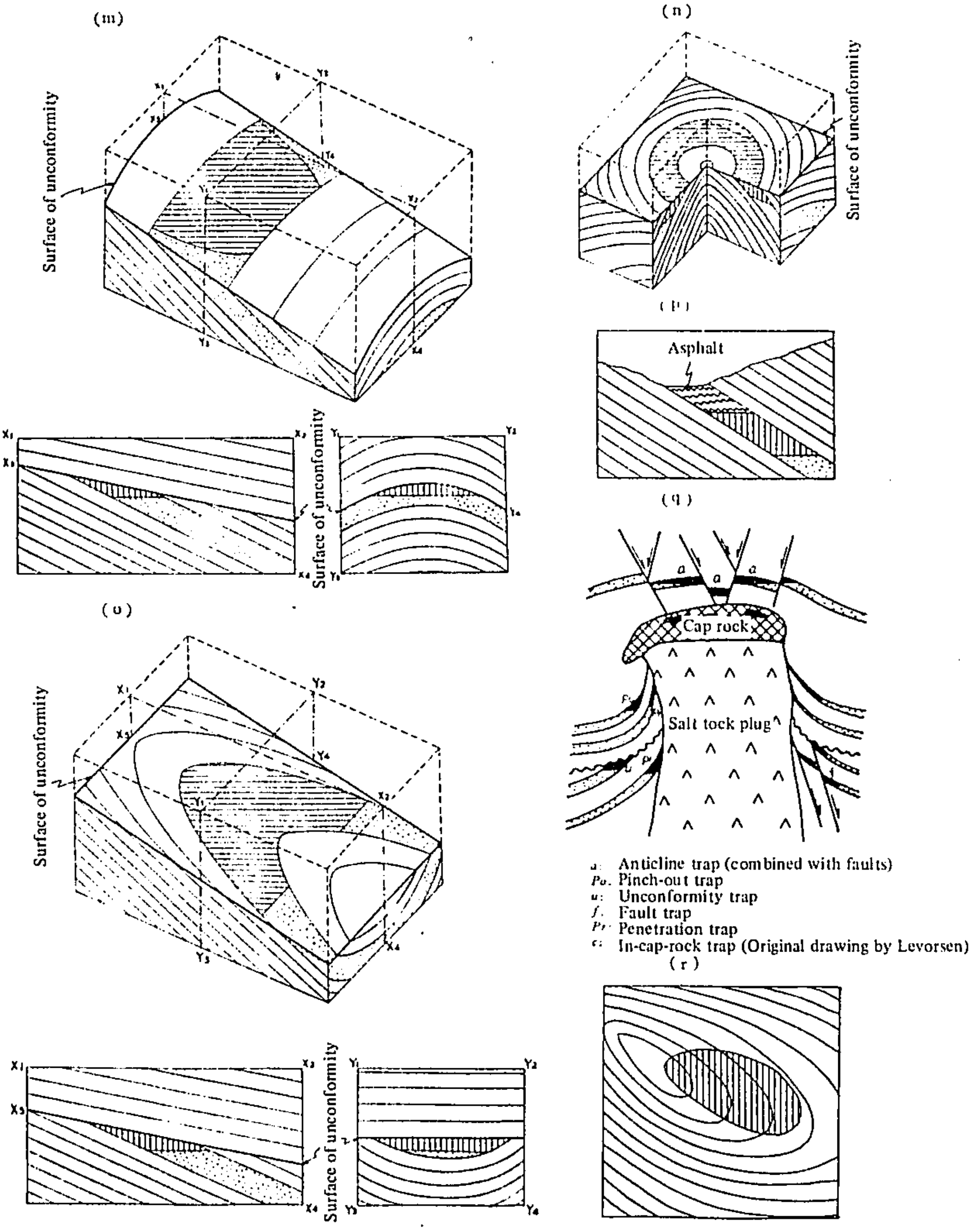


Fig. 3.8 Kinds of Traps (continued)



a: Anticline trap (combined with faults)
Po: Pinch-out trap
u: Unconformity trap
f: Fault trap
Pr: Penetration trap
c: In-cap-rock trap (Original drawing by Levorsen)

Fig. 3.8 Kinds of Traps (continued)

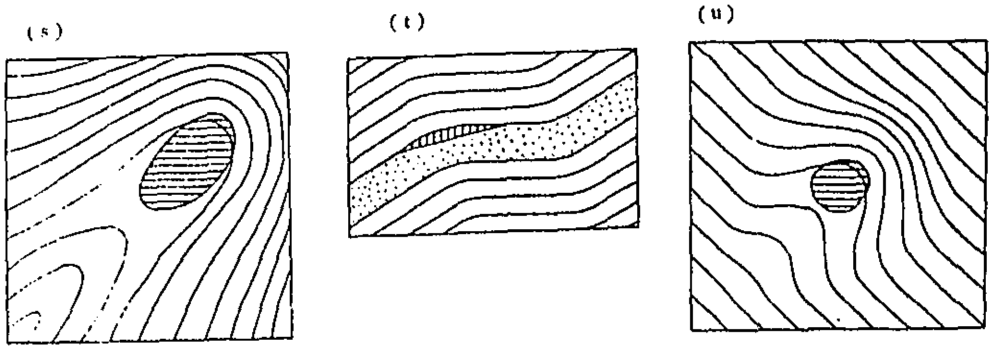


Table 3.3 Classification of Traps (by Mitsuchi, 1961)

- I. Traps of confinement structure in hydrostatic state
  - (A) Stratigraphic traps
    - ① Normal stratigraphic traps
      - (a) Lenticular sand traps (Fig. 3.8aL)
      - (b) Shoe-string-shape sand traps (Fig. 3.8aS)
      - (c) Reef traps (Fig. 3.8b)
    - ② Pseudostratigraphic traps
      - (a) Pinch-out traps (Fig. 3.8c)
      - (b) Permeability [difference]* traps (1.1 Fig. 8d)
      - (c) Unconformity traps (Original erosion surface is a curved surface.)
        - i) Cut-cap unconformity traps (Fig. 3.8e)
        - ii) Overlap unconformity traps (Fig. 3.8f)
  - (B) Structural traps
    - ① Closed anticline traps (including dome traps) (Fig. 3.8g)
    - ② Fault traps (in monoclinal structures) (Fig. 3.8h, i)
    - ③ Penetration traps
      - (a) Diapir traps (Fig. 3.8j)
      - (b) Traps around salt rock plugs (Fig. 3.8q)
      - (c) Traps around intrusive bodies of igneous rocks
    - ④ Traps of combinations of anticlines (either open or closed) and faults (Fig. 3.8k)
  - (C) Combination [stratigraphic-structural]* traps
    - ① Combinations of anticlines and stratigraphic traps

      Examples:
      - a) Lenticular sand traps over anticlinal structures (whether anticline is open or closed)
      - b) Pinch-out traps over anticlinal structures (whether anticline is open or closed)
      - c) Unconformity traps over anticlinal structures (whether anticline is open or closed) (Fig. 3.8 l, m)
      - d) Bald-headed anticlinal (dome) traps (closed anticline) (Fig. 3.8n)
    - ② Combinations of faults and stratigraphic traps

      Example: Pinch-out trap cut by a fault
    - ③ Combinations of synclines and unconformity traps (Fig. 3.8 o)
  - (D) Pseudostratigraphic traps
    - ① Fissure permeability [difference]* traps (where fissures develop locally in shale, etc.)
    - ② Salt-rock-plug cap-rock traps (Fig. 3.8q)
    - ③ Asphalt-blockage traps (Fig. 3.8p)
  - (E) Aggregation traps

    Salt rock dome traps (Fig. 3.8q)
- II. Traps of confinement structure assuming a marked hydrodynamic state
  - ① Traps partially distributed in anticlines (whether anticline is open or closed)
    - a) Traps very partially distributed toward one wing-side of anticlines
    - b) Traps very partially distributed toward a sinking part of anticlines
    - c) Traps very partially distributed toward one wing and sinking part of anticlines (Fig. 3.8r)
    - d) Nose traps of anticlines (Fig. 3.8s)
  - ② Traps in monoclinal structure
    - a) Step structure traps (Fig. 3.8t)
    - b) Nose structure traps (Fig. 3.8u)
    - c) Permeability difference traps (Oil-water contact surface is curved) (Fig. 1.1 - 3)
- III. Traps other than I and II

  Example: Synclinal traps

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* Note: Parenthesized words are often omitted.

Among the above-listed traps, the ones important as containing petroleum deposits are Ⓐ stratigraphic traps of (1) group, Ⓑ structural traps, Ⓒ combination stratigraphic traps of (1) group, Ⓑ structural traps, Ⓒ combination stratigraphic-structural traps, and Ⓔ agregation traps. Fig. 3.9 illustrates a reef trap, which is a stratigraphic trap, and Fig. 3.10 a salt dome trap.

It must be added that this paper is based on the chapter on deposits in "Petroleum Mining Handbook."

3.3 Reservoir Rocks

3.3.1 Kinds of Reservoir Rocks

The most commonly found reservoir rocks are sandstone and carbonate rocks. However, there are cases where igneous rocks, in the broad sense of the term, are predominant as in Japan, while there are peculiar cases where shale and metamorphic rocks have become reservoir rocks. Michael Hullbooty, who investigated over 266 large oil-gas fields of the world, presented in 1970 the following figures of occurrences of reservoir rocks by kinds.*

Sandstone	62%	(59%)
Carbonate rocks	38%	(41%)

His gifures show very little difference from the parenthesized ones given by Nebel in 1956.

Fig. 3.9 A Typical Reef Trap

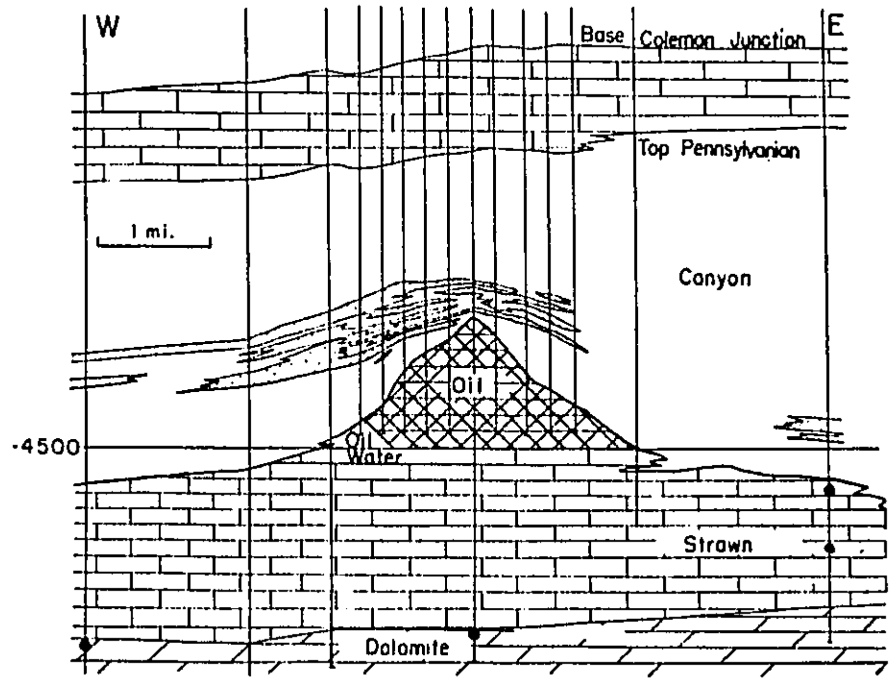

FIGURE 7-46
Section through the North Snyder pool in the Scurry-Snyder reef area of western Texas. The trap is in an organic reef of Canyon age built up from a floor of Strawn limestone (Pennsylvanian). The slight folding of the sands above the reefs may be the result either of initial dips or of compaction of the shales intervening between the sands and the underlying reef. The lack of shallow structure is noticeable, a characteristic that makes exploration for reefs extremely difficult. [Redrawn from Keplinger and Wanenmacher, World Oil, September 1950, p.182.]

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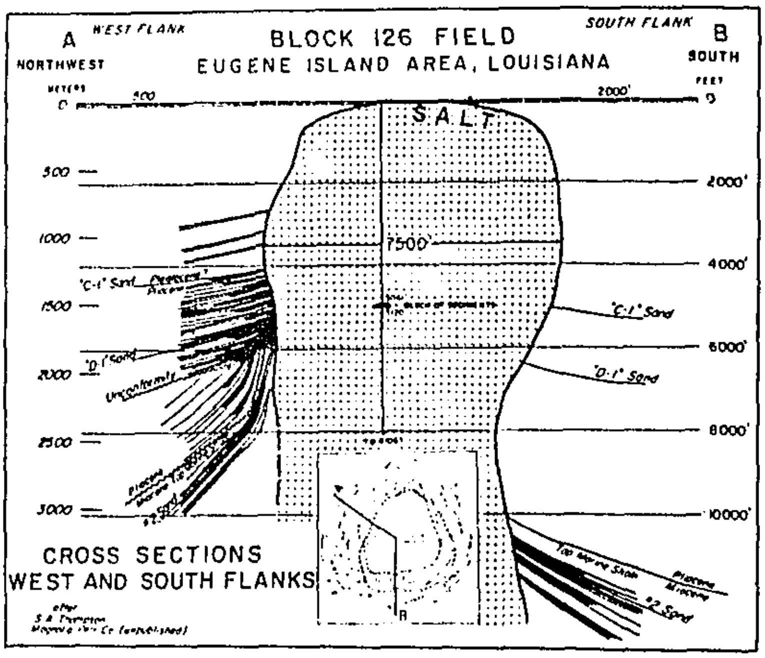
* Note: The percentages are values against mineable reserves. 6,000 cu.ft. is regarded as equivalent to 1 bbl. The figures in parentheses exclude the Middle East.

Fig. 3.10 A Typical Salt Dome Trap

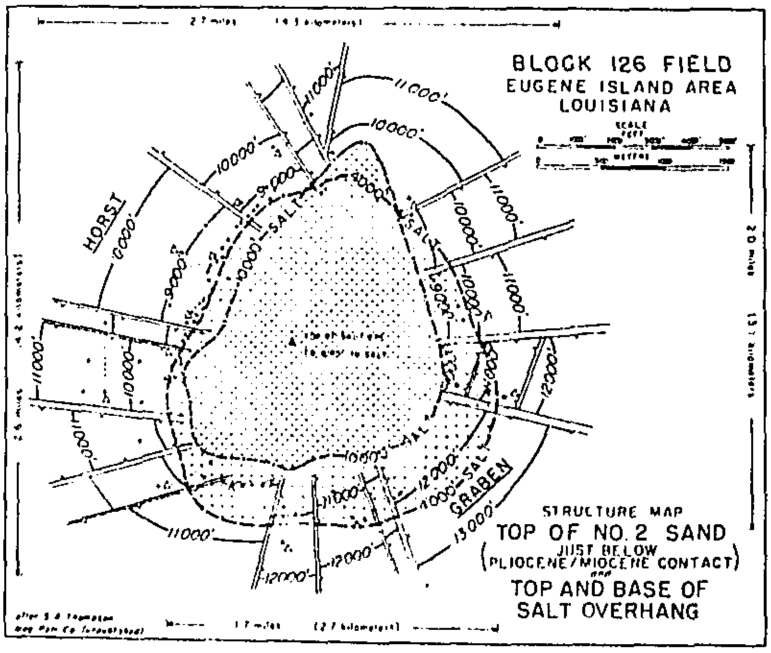
(a)



—Cross section of west and south flanks of Block 126 dome, Eugene Island area (Gulf of Mexico), Louisiana. From Atwater, 1959.

(b)

GROVER E. MURRAY



—Structure-contour map of Block 126 dome, Eugene Island area (Gulf of Mexico), Louisiana. From Atwater, 1959.

The quality and three-dimensional figure of reservoir rocks are governed by the past sedimentation environment. From this viewpoint comes the importance attached to sedimentological studies in exploration of stratigraphical traps mentioned later, and also investment by the major oil interests in investigation of delta sediments of the Holocene epoch, and sedimentation system and turbidite of submarine canyons leading to deepsea floors. As petroleum exploration activities are directed to continental slopes in succession as a worldwide trend, stress will be laid more and more on sedimentological studies of the origin of reservoir rocks.

It may be added that the term "dirty sand" often seen in the literature of well-logging analysis is a well-logging term which refers to, in terms of sedimentary petrology, sand-mud thin alternation or lutaceous sandstone.

3.3.2 Rock Physics of Reservoir Rocks

(1) Porosity

Porosity (ϕ) is defined as follows:*

$$\phi = \frac{\text{Total volume of rock} - \text{Volume of granules}}{\text{Total volume of rock}}$$

Porosity is related to reserve calculations, recovery calculations, and the flow of fluids in reservoir rocks. Besides, shale porosity is in general used as a measurement for the burying history and compaction of strata.

In view of the continuity of pores, porosity is divided into effective porosity and absolute porosity. Most of the methods of measuring porosity employed in laboratories involve the former, but there is little difference between the two in case of intergranular porosity.

Most of carbonate rocks, except oolitic ones, have a small porosity. However, a large oil-producing capacity often displayed by carbonate rocks is accounted for by the development of fissures. It is said that fissures in networks promote fracture porosity. The porosity created by fracture, recrystallization, melting and so forth after formation of sedimentary rocks as in the above case is called secondary porosity. In contrast, the porosity of pores which, after being formed at the time of sedimentation, have shrunk and been preserved is called primary porosity.

With a gradual sedimentation of strata and an increase in their burying depth, intergranular porosity decreases. In the case of mudstone (including shale) which has not undergone metamorphosis, a regular relationship known generally as depth-porosity curve is found. As for sandstone, a similar relationship exists, although there is some scattering because of differences in granularity and texture. Hence, in case of great depths, the occurrence of hydrocarbons on a commercial scale in primary porosity areas is hardly expected even with the exclusion of the effects of primary movement and geothermal temperature.

(2) Permeability

Concerning the migration of fluids in permeable, porous bodies, as is well-known in the field of hydrology, there is Darcy's law (1856). This was later expressed as the equation of fluid potential by M. King Hubert (1956). In Darcy's law, flow velocity is in proportion to pressure gradient, and the proportional constant is equivalent to permeability. This relationship, however, does not hold when flow velocity is extremely large and Reynolds number becomes large as well.

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* Note: ϕ is often expressed in percentage (%). This has the same meaning as porosity (n) in soil mechanics; the relation with pore ratio (e) is: $e = \phi (1-\phi)$

Also, when this relationship is applied to a case other than single-phase flow, and if capillary potential is dominant in the environment, the term of capillary potential must be added to the potential equation as well.

In actual measurement of permeability, calculation is made with the following equation using single-phase fluid in straight-line flow:

$$q = \frac{KA}{\mu} \cdot \frac{P_1 - P_2}{L}$$

where
q : Flow rate (cm^3/sec)
K : Permeability (darcy)*
μ : Viscosity coefficient (centipoise)
A : Sectional area of core (cm^2)
L : Length of core (cm)
P_1 : Fluid pressure at inlet (atm)
P_2 : Fluid pressure at outlet (atm)

In case the fluid employed has great compressibility, the equation below is used:

$$q = \frac{KA}{\mu} \cdot \frac{1}{P_2} \cdot \frac{P_1^2 - P_2^2}{2L}$$

(q is volume measured at P_2)

Relationship between permeability of liquid and that of air

Absolute permeability values obtained by the above equation will not agree. Klinkenberg derived the following empirical equation from experiments where glass capillaries were used:

$$Kg = Ke(1 + \frac{4c\lambda}{r})$$

where
Kg : Gas permeability
Ke : Permeability of liquid or high-density gas
λ : Average free channels of gas molecule under the pressure at Kg measurement
c : Proportional constant
r : Radius of capillary

Since with ideal gas the average number of free channels is proportional to the reciprocal of pressure, the above equation, with the use of the average of inlet and outlet pressures, Pm, and new proportional constant, b, is turned into the following formula:

$$Kg = Ke\,(1 + \frac{b}{Pm})$$

Hence, where Pm varies proportionally, $Kg = Ke$. By seeking Ke for various Pm values and making a $Ke - 1/Pm$ plot, the value of liquid permeability can be inferred from gas permeability.

Permeability of multiphasic fluids

As against the absolute permeability of a single-phase fluid, the permeability in each phase in case of two or three phases is usually less than the absolute permeability taken as the maximum

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* Note: Dimension is $[L^2]$. Permeability coefficient in hydrology has a dimension of $[LT^{-1}]$, and in numerical value corresponds to K when μ is equal to 1cp. 1 darcy is equivalent to 10^{-5} m/sec.

value. Permeability in each phase is called effective permeability, and the ratio of effective permeability to absolute permeability is called relative permeability. The relative permeability of a two-phase system has been extensively studied, and has been measured with ease in laboratories to be utilized in oil reserve calculations.

<u>Relationship between permeability and porosity</u> (Table 3.4, Fig. 3.11)

There is no distinct correlation between porosity and permeability; at most, a proportional relationship of $\ln K$-ϕ in the same bed is reported in actual fields.

For an ideal model of a reservoir rock consisting of globules of the same diameter, the relationship between porosity and permeability is shown by Kozeny's equation:

$$K(\text{darcy}) = \frac{1.0133 \times 10^8 \phi^3}{5 \times S_V^2 \, r(1-\phi)^2}$$

where ϕ : Porosity

S_V : Specific area of granules

On the other hand,

$$S_V = \frac{6 \times (1-\phi)}{d\phi}$$

where d : Diameter (cm) of granule (globule)

While K can be estimated from the above two equations, it will be larger than the actual value as is obvious from the assumption.

(3) Wetting of reservoir rock granules and state of existence of oil

As stated, some water is present in oil reserves. In case of wet reservoir rocks, water is in a wetting phase and oil is in a nonwetting phase. Fig. 3.12 illustrates the behavior of the two in pores.

Under the condition of being wet with water, water adheres to the granule surfaces in the form of film. When water-saturation rate is extremely low, water exists in the form of rings centering on the contact point of granules; this state is called pendular saturation. It is presumed that, when the water rings are connected with each other only through film, water cannot migrate even with the action of a pressure gradient or electric force. As the water-saturation rate increases, the water rings come to communicate physically with each other (equilibrium water saturation rate), and as it increases further, the water will be enabled to migrate freely under a pressure gradient. This state of water is called funicular saturation. As the water saturation rate increases further, it is thought, oil is isolated in small insular drops in the pores (insular saturation for oil), and a great force will be needed to push out the oil drops into adjacent pores under such conditions. This force, known as threshold pressure, will be discussed later.

(4) Capillarity

It is known that standing a capillary tube on a water surface will induce a rise of water in the capillary tube. Likewise the capillary phenomenon takes place in porous rocks where granules aggregate.

The important actions of capillarity in oil and gas reservoirs are, first, the control of distribution of reservoir fluids in the original state, and second, participation in the mechanism of petroleum and gas [illegible] the pores. Distribution of fluids in a reservoir in Fig. 3.4 has been caused by capillarity, reservoir rock texture, and fluid density.

Fig. 3.13 shows the typical form of capillary pressure curve for the oil-water system in an oil

Table 3.4 Examples of Relations between Porosity and Permeability in Reservoir Rocks in the U.S. (Source: Katz (1959))

Formation rock	Porosity, %	Permeability, millidarcys
Bartlesville, Okla. (sand)	14.7	6.7
	19.4	48.7
	17.3	41.5
	15.8	16.2
	12.9	21.5
Benoist, Ill. (sand)	16.7	87.5
	14.2	15.7
	15.3	58.0
	12.5	20
	15.1	323
Cromwell, Okla. (sand)	13.9	171
	14.2	174
	16.3	366
	10.8	51
Cypress, Ill. (sand)	13.7	30
	16.4	249
	20	74
Elenberger dolomite, Tex.	5.4	1,285
Frio sand, Tex.	22.4	1,475
	18.1	42.2
	25.1	860
Gatehell sand, Calif.	13.9	965
	14.1	425
Glenn sand, Okla.	16.6	9.5
	16.3	10
	17.3	105
	20	302
Miocene sand, La.	36.1	578
	33.2	1,455
	39.4	745
	37.3	810
	37.5	360
	34.2	980
	32.2	1,040
Rodessa oolitic sandstone, La.	28.0	14.3
	30.5	207
	30.2	328
	30.2	220
	33.9	470
	28.9	344
	24.9	261
Tensleep sand, Wyo.	11.8	86
	18.0	53
	14.0	189
	12.9	119
	11.3	128
	9.3	9.7
Third Los Angeles sand, Calif.	19.1	99.5
	21.2	67
	22.1	84
	25.6	119
Wilcox sand, Okla.	19.8	242
	23.6	1,650
	23.7	2,150
	13.1	356
	19.2	456
Wilcox	18.1	155
	16.9	388
	13.4	67
	21.9	1,030
	19.1	786
	15.2	560
Woodbine sand, Tex.	26.8	2,110
	25.3	276
	23.8	111
	22.1	3,390
	27.7	859
	29.0	341
Bradford sand, Pa.	10.4	0.77
	12.6	1.67
	14.8	16.8
	14.2	2.7
	16.7	55.8

reservoir wet with water. In this diagram the level of capillary pressure where $P_c = 0$ is the free water level, below which water can move freely. The point D.P. is displacement pressure, which is the pressure required to start forcing a fluid (oil) in the nonwetting phase into a porous body at 100% water saturation. At the water saturation rate below the point of threshold pressure = 0, the oil in pores can migrate through pores depending on the pressure gradient. The point where water saturation rate further decreases and passes into pendular saturation state is called irreducible water saturation, in which Pc becomes extremely large. This indicates that further dewatering is not possible.

Displacement pressure is closely related to the function of the cap rock, which is described in the next section. Table 3.5 shows that, generally, the finer the grains of rocks, the higher the pressure.

Table 3.5 Displacement Pressure by Granularity in Water-oil System
(Source: M. King Hubert (1953))

Sediment	Grain Diameter (Millimeters)	Capillary Pressure (P) (Atmospheres)
Clay, very fine	10^{-4}	Approximately 40
Clay	Less than 1/256	Greater than 1
Silt	From 1/256 to 1/16	Between 1 and 1/16
Sand	From 1/16 to 2	Between 1/16 and 1/500
Granules	From 2 to 4	Between 1/500 and 1/1,000

3.4 Cap Rock

3.4.1 Cap Rock

Cap rock is the rock stratum which covers the top or sides of a reservoir rock and thereby prevents the escape of gas and oil.*

The cap rock is required to have a poor permeability and not to produce fissures easily by folding. These requirements are best met by salt rock with rich plasticity, followed by hard gypsum. Many of them are found in the Middle East areas and salt dome structures. Compact mudstone and shale are also found extensively as cap rocks. In this case, it is deduced that such mudstone and shale have functioned as petroleum source rock as well as cap rock, if they have been suitable as petroleum source rock and if there was a time when abnormal highpressure was present over a considerable thickness.

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* Note: Some scholars limit cap rock to salt dome and use the term roof rock for other cases. In Japan the latter is not used, partly because of difficulty in translation.

Fig. 3.11 Examples of Relationship Between Permeability and Porosity

Source: Levorsen (1967)

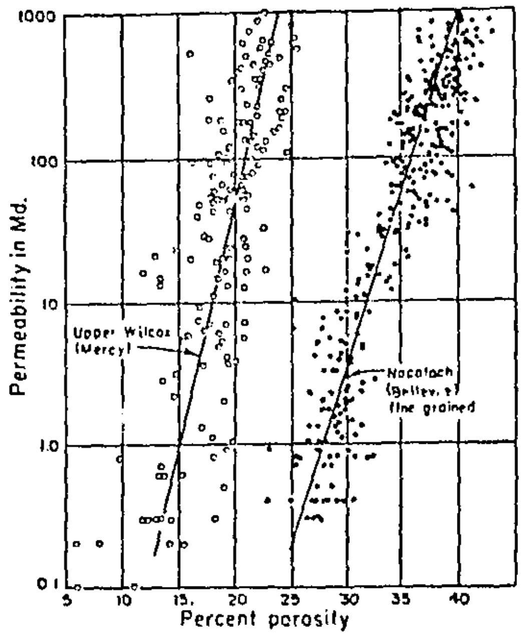


Fig. 3.13 Relationship Between Fluid Saturation Rate and Capillary Pressure

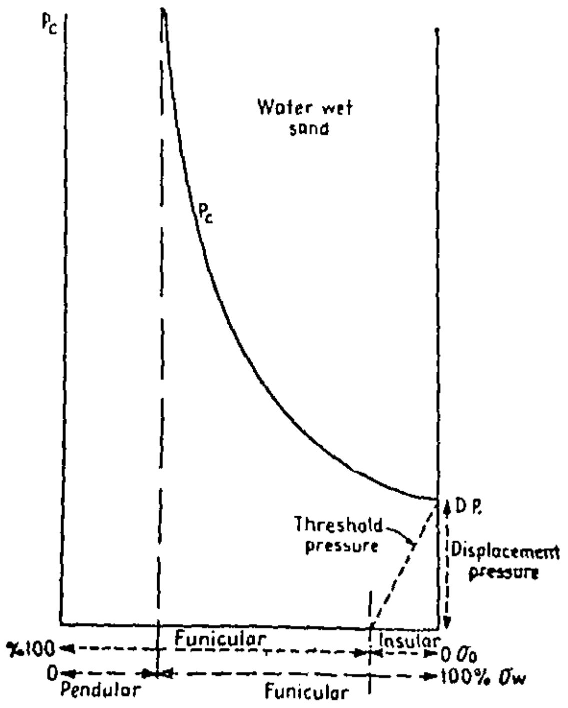
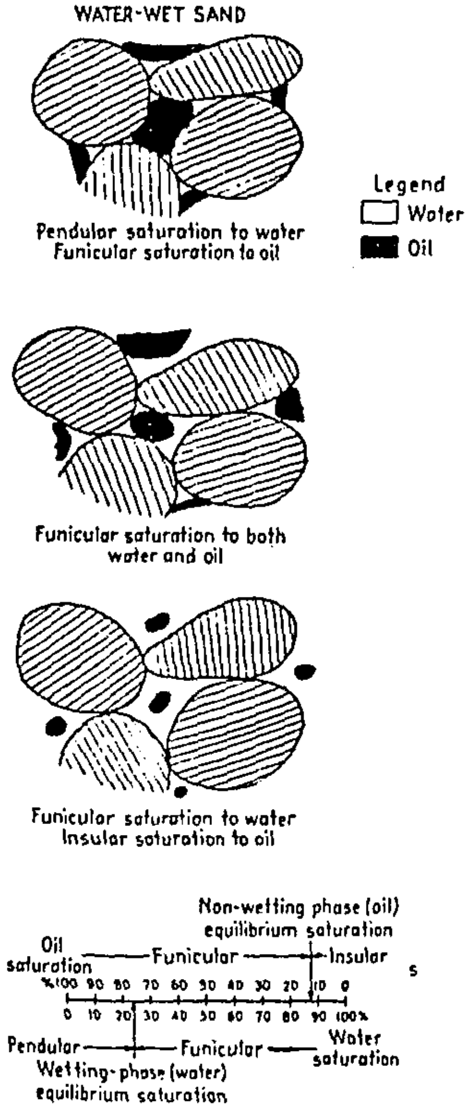


Fig. 3.12 States of Oil Existing in Water-wet Reservoir Rocks

Source: S.J. Pirson (1958)



Pendular saturation to water
Funicular saturation to oil

Funicular saturation to both water and oil

Funicular saturation to water
Insular saturation to oil

3.4.2 Function of Cap Rock

The mechanism by which cap rock prevents oil and gas from escaping upward can be easily understood from capillarity. Assuming that the wetting phase consists of water and the nonwetting phase of hydrocarbon (gas or oil) in the commonest state, and assuming a hydrostatic pressure, generally the following equation holds:

$$P_c = (\rho_w - \rho_h)gZ \quad \text{...} \quad (1)$$

where P_c (dyne/cm^2) : Capillary pressure
g (cm/sec^2) : Gravitational acceleration
Z (cm) : Height from free water level
ρ_w (gr/cm^3) : Density of water
ρ_h (gr/cm^3) : Density of hydrocarbons

If the pressure of water at the free water level of a water-hydrocarbon system is denoted by P_{wl}, then the pressure of oil and water at Z will be $P_o = P_{wl} - \rho_o gZ$ and $P_w = P_{wl} - \rho_w gZ$, respectively.

If the displacement pressure of cap rock at the highest point of reservoir is denoted by P_{dc}, then hydrocarbons cannot enter the cap rock under the condition of $P_c \leqq P_{dc}$. Thus, the column of hydrocarbons where $P_c = P_{dc}$ reflects the maximum volume of hydrocarbons that can be accumulated in that structure. Thus equation (1) is transformed into:

$$Z_{max} = P_{dc}/(\rho_w - \rho_h)g \quad \text{......................................} \quad (2)$$

where

$$Z_{max} = H_{hmax} + H_w \quad \text{..} \quad (3)$$

H_{hmax} denotes the height of the continuity phase of the maximum hydrocarbon column that can be accumulated, and H_w the height from the free water level up to 100% of water saturation rate.

From Equations (2) and (3), we get

$$H_{hmax} + H_w = P_{dc}/(\rho_w - \rho_h)g \quad \text{............................} \quad (4)$$

On the other hand, H_w is determined by the displacement pressure of reservoir rock (P_{dr}). Hence:

$$P_c = P_{dr} = (\rho_w - \rho_h)g \quad \text{..} \quad (5)$$

From equations (4) and (5)

$$H_{hmax} = (P_{dc} - P_{dr}) / (\rho_w - \rho_h)g \quad \text{.....................} \quad (6)$$

Therefore it is found that the trap capacity of a cap rock is proportional to the difference in displacement pressure between reservoir rock and cap rock as shown by equation (6). As is clear from the equation, in the same geological structure, the column of gas is lower than that of oil. In other words, gas is more liable to accumulate in a relaxed structure.

3.8 Origin of Petroleum Deposits

3.8.1 General

Discussion of the origin of petroleum deposits should be based on comprehensive scientific studies of the following problems:

(1) From what, when and how was petroleum created?
  – Problem of the origin.
(2) In what places does petroleum occur?
  – Problem of distribution of deposits seen from geographical and geological viewpoints.
(3) How was petroleum accumulated there?
  – Problem of migration and accumulation.

Finally,

(4) In what limits are the deposits?
  – Problem of limits of deposit formation.

When one looks into any of these problems, he will find many unsolved questions there. The difficulty in solving the questions lies in the fact that, unlike in the case of metallic ore and coal deposits, petroleum is thought to have migrated to other places from the place of origin and have accumulated there to form deposits. In addition, such difficulty can be explained by comparison with metallic ore and coal deposits; metallic ore deposits were probably formed in a comparatively short period, and as for coal deposits, although a considerably long time was required for formation of bituminous coal and anthracite which have undergone considerable carbonization, peat which is to be regarded as their predecessor can be observed in actuality; on the other hand, a period of millions of years was required for petroleum to be created and to form deposits, and the intermediate substances are very hard to grasp.

In the last few years, however, signs of solution of these questions have appeared rapidly owing to the efforts of many researchers and engineers in this field spurred by the stringent situation of petroleum supply-demand and to the advances in science and technology. Recent findings will be summarized, focusing our attention on firmed-up theories.

(1) Information on the origin of petroleum

ⓐ Properties of petroleum

Although much has become known now about petroleum properties, the knowledge is still limited to gasoline and kerosene fractions; very little is known about lubricating oil and heavier fractions. Out of the knowledge so far acquired, a few important points in relation with the origin of petroleum will be introduced below:

i) Petroleum is primarily a mixture of various hydrocarbons.

ii) The hydrocarbons that make up petroleum are paraffins, naphthenes and aromatics, but do not include unsaturated aliphatic compounds.

iii) Normal paraffins in crude oil consist of about the same quantities of compounds with odd and even numbers of carbon atoms.

iv) In most cases crude oil exists in the form of micells and contains some asphalt.

v) Often found as impurities in crude oil are naphthenic acid, other organic acids, oxygen compounds including sterols, sulfur and nitrogen compounds (asphalt in general contains oxygen, nitrogen and sulfur). Ash of crude oil contains trace quantities of various metals, such as sodium, nickel, copper, zinc, lead, vanadium and uranium. Vanadium and nickel are contained as complex salts of porphyrin compounds (a derivative of chlorophyl).

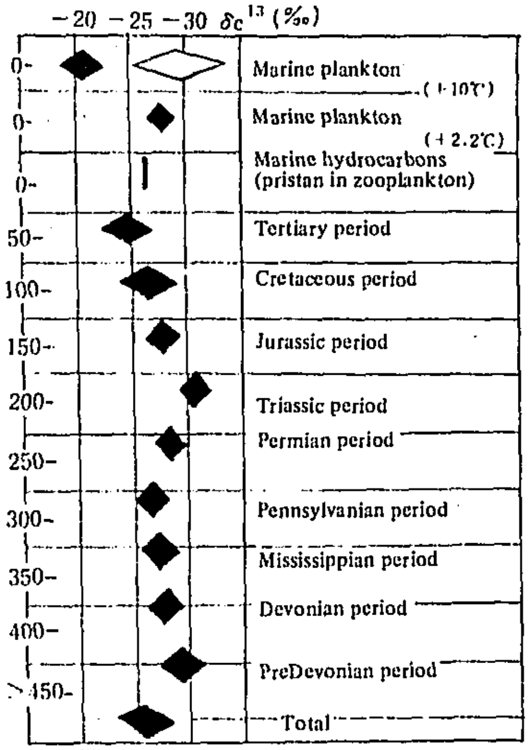
vi) Most crude oils have optical activity, which is said due to the steroids in them. Usually crude oils of younger geological age have stronger optical activity.

vii) The crude oil δC^{13} value (equivalent to C^{13}/C^{12}) is approximately equal to that of marine plankton, in particular, plankton found in cold currents. See Fig. 3.22.

ⓑ Occurrence of petroleum

From the geological viewpoint, most of the petroleum in the world occurs in the rocks of sediments in lakes, marshes, beaches and the sea, namely, sedimentary rocks. Very rarely it occurs in igneous or metamorphic rocks, but in those cases these oil-bearing rocks are found directly under a formation of sedimentary rocks and the oil deposit exists at points where the oil-bearing rocks contact the sedimentary rocks.

Fig. 3.22 δC^{13} Value of Crude Oil



(Original diagram by Degens)

Oil deposits occur throughout the world, wherever these are sedimentary basins where there have developed formations of marine sedimentary rocks which have not been much altered; the size of reserves is a different matter.

In case of terrestrial sedimentary rocks, the occurrence depends to a great extent on the scale of sedimentation and lithofacies. Also the geological ages of the strata containing oil deposits cover almost all ages from the Cambrian period to the Quaternary period. It is thought that deposits in Quaternary period rocks have not been formed there, but have migrated from strata of Tertiary or older geological ages.

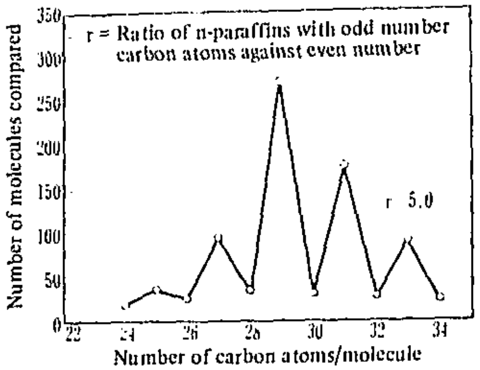
The above descriptions have centered on petroleum accumulated in deposits. Now let us summarize the information on petroleum in rocks other than those of oil reservoirs of geological ages and on hydrocarbons in Holocene sediments.

ⓒ Research information on formation of petroleum

Hunt et al. analyzed samples–mainly drill cores–of shale, limestone, etc., other than oil reservoir rocks of various geological ages, in oil fields throughout the U.S. and showed that all of them contained some bituminous substances, hydrocarbons in them, asphalt components and petrogen (kerogen). Other researchers later made detailed analyses and experiments on the bituminous substances, in particular, hydrocarbons, and revealed that the hydrocarbons were very similar to 400 to 500°F and heavier fractions in crude oil. The hydrocarbons in asphalt were found similar to those in crude oil. It was also revealed, in particular, that in strata deeper than the level of oil-producing strata, normal paraffins of odd and even numbers of carbon atoms were contained in almost equal quantities as in the case of crude oil. These reports thus indicate that a considerable amount of petroleum exists nonaccumulated, and in sedimentary basins the rocks contain tens or hundreds of times as much petroleum.

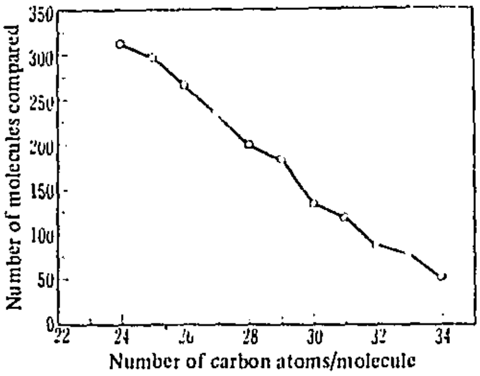
Fig. 3.23

a . Predominance of Odd Number Carbon Compounds in Holocene Sediments



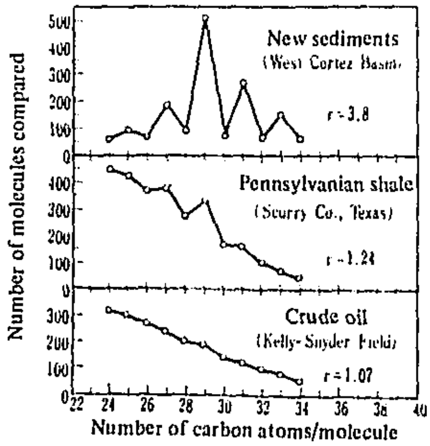
(Original diagram by E.E. Bray and E.D. Evans)

b Lack of Predominance of Odd Number Carbon Compounds in Crude Oil of Old Ages



(Original diagram by E.E. Bray and E.D. Evans)

c Extreme and Intermediate Cases of Predominance of Odd Number Carbon Compounds



(Original diagram by E.E. Bray and E.D. Evans)

In the meantime, a study of hydrocarbons in Holocene sediments was initiated in the 1930s by Trask and others. Then, in 1952, Smith detected small amounts of hydrocarbons in Holocene sediments in the seabed off the Gulf Coast. C^{14} age measurement disclosed that the hydrocarbons were 11,800 to 14,600 ± 1,400 years old and that they were not seepages from older strata below. Further, it was found that a considerable quantity of asphalt was also contained there and that this was in more significant quantities than hydrocarbons and more prominent than the asphalt of geological ages. Stevens et al., upon detailed examination of hydrocarbons of the Holocene sediments in the Gulf Coast, found that, unlike hydrocarbons in sedimentary rocks of Geological ages, normal paraffins with odd number carbon atoms were predominant over those with even number carbon atoms, and aromatic hydrocarbons were of very simple structure compared with those in crude oil and sedimentary rocks. Notable is the fact that carbon number curves for normal paraffins show characteristic difference (See Fig. 3.23 a, b and c). Meanwhile, the fact that the alkyl radicals of fatty acids contained in organisms have an odd number of carbon atoms deserves attention in view of the predominance of normal paraffins with odd number carbon atoms in Holocene sediments.

(2) Theories on the origin of petroleum

Many hypotheses have been advanced about the origin of petroleum. They are roughly classified as follows:

- ⓐ Theories of inorganic origin
  - Theory of carbide origin
  - Theory of volcanic origin
  - Theory of space origin
- ⓑ Theories of organic origin
  - Theory of plant origin
    - Terrestrial plant theory
    - Marine plant theory
  - Theory of animal origin
  - Theory of animal and plant origin
  - Theory of sapropel origin

The theory of carbide origin, principally supported by chemists, sets forth: alkali metals and carbon dioxide gas existing in the earth were turned into carbide through reaction at high temperature, the carbide reacting with water was changed into acetylene, which then underwent polymerization and condensation to produce various hydrocarbons which rose to shallow underground parts to form a deposit. This theory was evolved, in the period from 1866 to 1920, by synthetic chemists on the basis of successful laboratory experiments.

The theory of volcanic origin was founded on the fact that volcanic gas contains methane, that there are signs of petroleum in lava, that volcanic rock intrusions are occasionally found near petroleum deposits, and so forth. This theory is divided into two: one saying that volcanic activities cause synthesis of carbon and hydrogen in the earth, and the other saying that organic matter was subjected to dry distillation by the heat of magma and was turned into hydrocarbons. The latter is a sub-theory, which could be treated as belonging to the organic origin theory.

The theory of space origin, stemming from the presence of hydrocarbons observed in meteors, sets forth that hydrocarbons had been synthesized before the generation of living things and had existed already when the earth was created, and that they matured with the growth of the earth, cohered and formed a deposit. This theory reappeared recently as the theory of hot carbon synthesis, which is based on superhigh-temperature chemical synthesis technology–e.g. plasma reaction synthesis technology–having made a notable progress these years. It may be considered a by-product of advances in science and technology related to outer space development.

The theories of plant origin are roughly divided into those of terrestrial plant origin and of marine plant origin. Among the terrestrial plant origin theories, there is a theory that petroleum was created by dry distillation of coal; and another says that, in the process where terrestrial plants were deposited with clay and sand and were decomposed, they were changed into coal when their volatile components dissipated freely, while petroleum was formed when they were subjected to pressure in a hermetically sealed system. The latter may be called the theory of coal-petroleum joint origin.

In contrast, the theory of marine (or "aquatic" in a broader sense) plant origin maintains that aquatic plants such as diatom and seaweeds or phytoplankton and the like are the origin.

On the other hand, the theory of animal origin says that petroleum comes from the remains of animals, on the grounds that numerous animal fossils are often found near oil reservoir rocks. Particularly the theory of fish oil origin gained support, because dry distillation of fish oil generates a substance similar to petroleum and that petroleum is accompanied by brine resembling sea water.

The theory of animal and plant origin goes that petroleum derives from plants in bituminous shale and from animals contained in limestone.

The theory of sapropel origin says that petroleum originates from sapropel which is formed by decomposition and fermentation, in oxygen-poor stagnant waters, of fats of lower algae, lipids of aquatic plants, and resinoids of pollen and spores, and so forth. The theory of petroleum origin published by Dr. Jun-ichi Takahashi at Tohoku University in 1922 also is a theory of sapropel origin. According to him, petroleum source organisms are turned into a stable intermediate substance looking like wax through biochemical action; this is newly formed into a gel-like substance in which organic and inorganic matters are mixed through adsorption with inorganic gel-like substances, and through saponification of branches of carboxyl groups; this new substance, called pyrobitumen or kerogen, is partly solated with the increase of rock pressure to become petroleum.

* * *

In the above, theories so far advanced concerning the origin of petroleum have been briefly described. New let us summarize the various statements made in (1) above.

ⓐ Most petroleum deposits worth working are found in areas of sedimentary rocks; this is one of the important facts that support the theory of organism sediments origin.

ⓑ Petroleum usually contains certain substances giving rotatory polarization (optically active substance); this fact indicates, at least, that organic matter produced by living things participates in petroleum formation, because living things alone can produce only one part of antipodes of compounds having asymmetric carbon atoms.

ⓒ The fact that petroleum contains porphyrin proves that petroleum has been formed in a comparatively low temperature process. It has been experimentally confirmed that porphyrin is readily oxidized and that, at temperatures above 200°C, decomposition proceeds rapidly. In the 1960s, porphyrin was discovered in meteors by Hodgson et al. and thereafter it was synthesized under nonbiological conditions, giving rise to moves to deny the origin in organic substances produced by living things. This discovery, however, should not be connected directly with the origin of petroleum, but should be regarded as having important meanings concerning the origin of life and the creation of living things.

ⓓ There are not a few indications of causal relations suggesting that hydrocarbons in crude oil and Holocene sediments are derived chemically from organic matter produced by living things.

In the light of the properties and occurrence of petroleum as above-stated, it may safely be said that petroleum was formed from organisms produced by living things. Also the presence of petroleum components and similar components in sedimentary rocks naturally induces us to think that those organic substances were produced by aquatic, in particular marine, life, and were mixed with mineral detritus, deposited at the bottom of water, and subjected to various actions by the organic matter in the sediments to form petroleum.

We will discuss in the following the sedimentary rocks that are thought to have deposited organisms therein in considerable quantities, formed much petroleum, and contributed to the formation of petroleum deposits (such sedimentary rocks hereinafter referred to as petroleum source rocks), and the problems of migration to and accumulation in reservoir rocks, and how the deposits came to decrease.

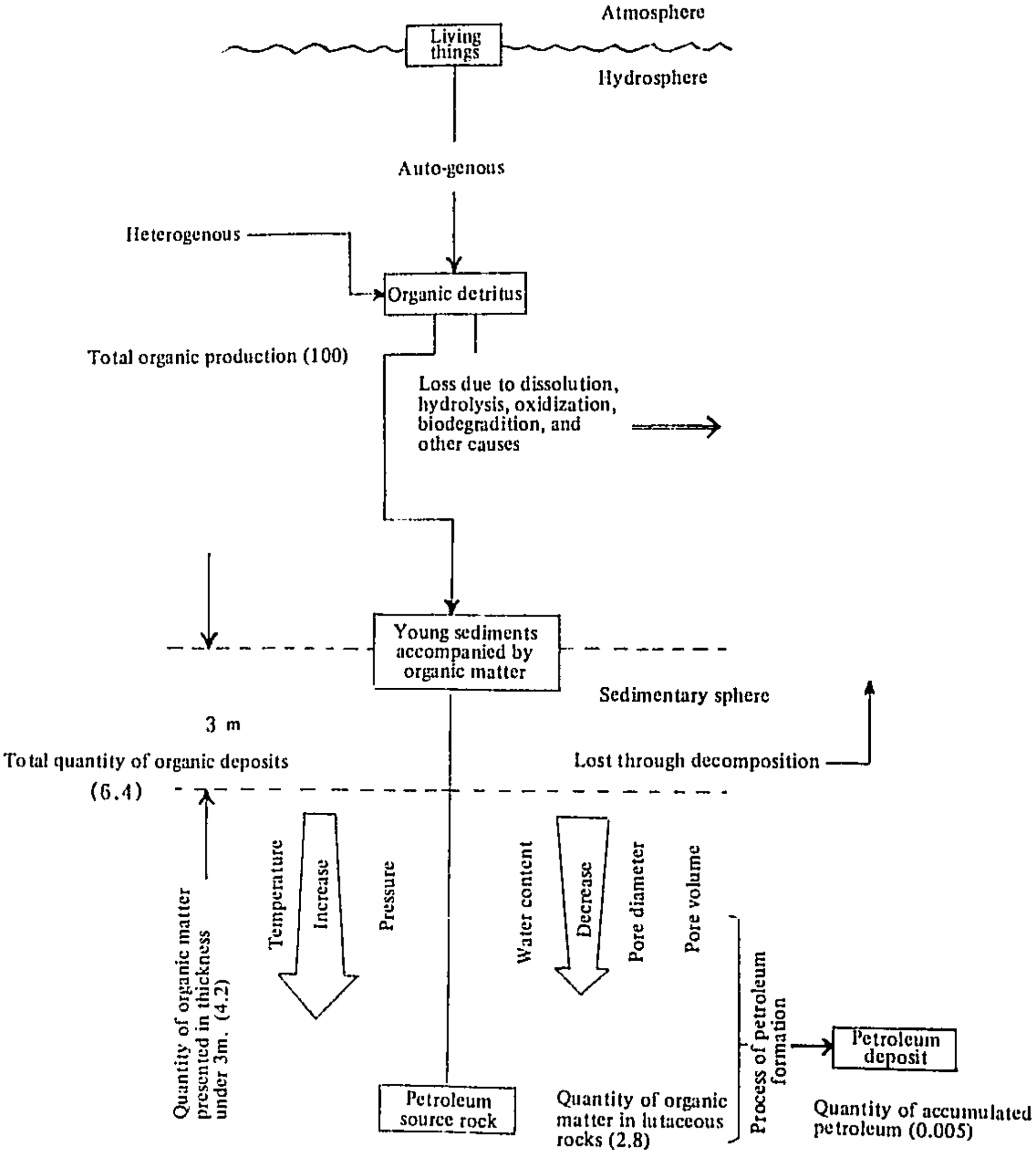
3.8.2 Petroleum Source Rocks

The total amount of organic substances in the whole globe is estimated at about 3×10^{15} tons, about a half of which is held by sedimentary rocks on land and continental shelves. Out of it, the amount of petroleum components dispersed in fine-grained sedimentary rocks is estimated to be about 60×10^{12} tons. It is said that only one percent of it, namely about 0.6×10^{12} tons, has been accumulated in reservoir rocks.

This indicates an extremely low efficiency of the overall process that produces petroleum available for actual use. Thus it is surmised that petroleum source rocks that have actually contributed to oil deposits are considerably limited.

The processes from the production of organic matter in the hydrosphere and sedimentation to the formation of petroleum source rocks are illustrated schematically in Fig. 3.24. The organic matter participating in sedimentation consists of autogenous organisms produced in the hydrosphere (aquatic animals and plants; those which participate in sedimentation are plankton, lower algae and the like) and heterogenous organisms transported through rivers and streams (mostly detritus of terrestrial plants). Most of them (more than 90%) decompose in the hydrosphere and dissolve away there. The part participating in sedimentation is only 6.4% of the organic matter in the hydrosphere. In the initial period of sedimentation, about 30% of it, decomposed by microbial action, dissolves away into the hydrosphere and is excluded from sedimentation during the course of sedimentation about three meters deep. The remaining 70% enters the sedimentation zone, and about 66% is said to survive eventually in the rock zone, passing through the process of diagenesis. Some of the organic matter may, in the diagenetic process, decompose into CO_2, NH_3 and H_2O, turning inorganic, and either settle as a carbonate or dissolve in water as HCO_3^-, NH_4^+ and dissipate into the hydrosphere. Some components may dissolve and also dissipate in the hydrosphere. It is calculated that in overall average only 0.014% of all organic matter in sedimentary rocks has been accumulated as petroleum. According to data from a survey conducted by Emery over Los Angeles Basin, however, 0.2% has been accumulated as petroleum. Such a high accumulation is seen only in sedimentary rocks with a high concentration of organic matter and a high rate of conversion into petroleum as in Los Angeles Basin; petroleum has been accumulated there with an efficiency 14 times as high as the average for the whole world. Sedimentary rocks that have been able to contribute thus efficiently to the formation of petroleum deposits are referred to as petroleum source rocks. Petroleum source rocks are mostly composed of fine-grained sediments, viz., lutaceous rocks or shale. It was pointed out by Trask et al. in 1932 that the finer the component grains of detritus sediments, the larger the quantity of organic matter found there in sedimentary basins of a certain limited area, according to research into Holocene sediments. Later, this theory was generally accepted as it was supported by many findings of investigations. Table 3.11 shows some examples of sediments on continental shelves. As for how the relationship was formed between the size of sediment grains and the quantity of organisms, one may cite the approximation of specific gravity of detritus organic matter and fine inorganic particles. As a result of this approximation, the two come to have a similar settling velocity, so that in places of low velocity of flow, organic matter concentrates with sediments composed of fine particles. It is thought that in this manner potential petroleum source rocks may be formed of fine-grained sediments with a high organic content. Now let us examine what kinds of organic matter are deposited in what sedimentation environment.

Fig. 3.24 Schematic Diagram of the Processes from Sedimentation of Organic Matter to Formation of Petroleum Source Rocks



Note: Figures in parentheses were taken from data of investigation in Los Angeles Basin by K.O. Emery.

Table 3.11 Organic Matter in Holocene Sediments

ⓐ Quantity of Extractable Organic Matter in Seabed Sediments and Their Element Composition (Smith, 1945) – An example of the Gulf of Mexico

Type of sediment	Quantity of total organic carbon (weight % in dry sample)	Quantity of extractable organic matter (% in total organic matter)	Element composition of extractable organic matter C	O	H	N
Sandy sediment	0.69	38.3	84.32	3.48	11.68	0.34
Clayey sediment	1.00	2.9	76.90	10.39	11.86	0.88

ⓑ Composition of Organic Matter Classified by Group of Sediments on a Continental Shelf in the Bering Sea (75 to 140 m depth) (Bordouskiy, 1965)

Kind of sediment	Quantity of total organic carbon (% in dry sample)	Composition by group of organic matter (%)			
		Readily hydrolizable substances	Bituminous substances	Humic acid	Residual organic matter
Medium-size sandy sediment	0.0.32	59.4	6.6	15.6	18.4
Coarse silt	0.0.70	35.8	4.0	28.5	31.7
Fine silty mud	0.0.97	26.7	3.6	27.8	41.9

(1) Sedimentation environment and kinds of sedimentary organic matter

In such places as lagoons, high-concentration organic sediments of large terrestrial plants tend to be formed. Most of them go through the mutation process of turning humic, changing into peat, lignite, brown coal and bituminous coal then into anthracite. In lakes and marshes, algae, freshwater plankton, spores, pollen and resin are the main components of sediments, which form a considerable amount of concentration-type organic sediments. They turn into sapropelic mud, then into cannel coal or boghead coal. Occasionally, it is said, sapropelic mud change into petroleum, but actually in most cases it is converted to coal. If it contains comparatively large quantities of inorganic matter, it turns into what is known as oil shale.

Depressions are often found on continental shelves, and these are called basins. In such places, a comparatively stagnant environment is created, so that fine-grained sediments are apt to be formed there. The organic substances entering into sedimentation are roughly classified into two kinds: one is detritus of terrestrial plants transported there through rivers and streams (this is referred to as heterogenous organic matter as aforementioned), and the other is marine plankton, algae and the like (this is called autogenous organic matter as mentioned before). It is considered that most of petroleum stems from such organic matter subjected to sedimentation. The above is summarized in Table 3.12.

Table 3.11 ⓑ shows the composition of organic matter (classified by sediment groups) found on the continental shelf of the Bering Sea. Table 3.13 sets forth similar data about Holocene sediments on continental slopes and inland seas published by Shabarova in 1955.

The hydrolyzable substances in Table 3.11 ⓑ contain proteins and hydrocarbons. What is classified as fatty matter in Table 3.13 is the so-called "lipid fraction" and covers not only lipids in the exact chemical meaning but hydrocarbons as well; it may be said to correspond to the bituminous substances in Table 3.11 ⓑ. Also the humic acid and residual organic matter in Table 3.11 can be regarded as approximately corresponding to the nonhydrolyzable substances in Table 3.13.

It is notable in both tables that substances corresponding to residual organic matter including

Table 3.12 Sedimentation Environment and Sedimentary Organic Matter

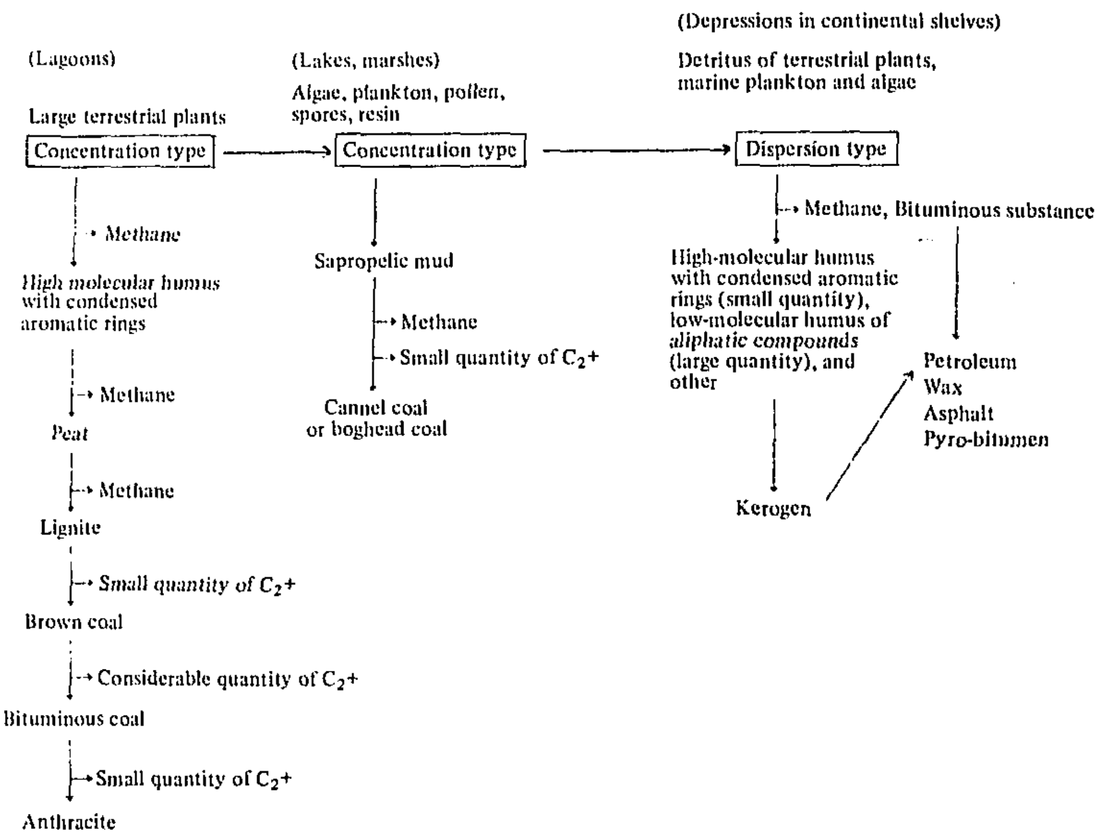


Table 3.13 Composition of Organic Matter in Holocene Sediments (Shabarova, 1955)

Area	Sediment	Total organic matter (weight percentage /dry sample)	Lipids	Protein	Hydro-carbons	Nonhydro-lyzable substances	Wholly hydrolyzable substances
Continental shelf of eastern USSR							
988 m deep	A D	4.57	4.38	6.96	0.74	87.97	12.03
1,497 m deep	A D	8.48	5.91	7.75	痕跡	87.34	12.66
Black Sea, beach mud							
Trace	G	7.37	7.75	56.31	10.83	24.69	75.31
50 m deep	A G	3.89	2.55	9.41	0.00	88.04	11.96
220 m deep	A B	4.89	2.33	10.73	0.00	86.84	13.16
294 m deep	A B	8.05	2.09	3.17	0.00	94.74	6.26
Caspian Sea							
18 m deep	A S	4.89	8.70	7.48	1.03	82.79	17.21
18 m deep	A G	4.56	7.68	9.43	1.54	81.35	18.65

A: Clayey matter B: Black mud D: Diatomaceous matter G: Gray mud S: Silty matter

(Taguchi, 1970)

humic acid occupy an overwhelmingly large portion in marine sediments on continental shelves and other parts. As Table 3.14 indicates, organic substances constituting biological bodies and those in marine sediments are both of similar elemental composition, though there is a little difference. Concerning composition in terms of organic substances, whereas it can be determined rather easily for organisms, it is too complicated to deal with when organic substances enter sediments where they turn into residual polymers. Nevertheless, as a result of steady research over the last 20 years or so, some light has been shed on the organic substances in sediments. Some of these findings which seem to be important in relation to petroleum formation will be described.

Table 3.14 Elemental Analyses of Organic Contents of Seabed Sediments and Geological Substances

Sample	Elemental analyses (%)				Other elements	Researcher		
	C	O	H	N				
Diatoms	45.9	35.7	9.4	9.0	n. d.	Vinogradoff	(13)	(1953)
Copepods	50.0	32.0	8.0	10.0	–	Trask	(2)	(1939)
Marine Sapropel	52.0	30.0	6.0	11.0	0.8	Zo Bell	(14)	(1944)
Holocene seabed sediments	56.0	30.0	8.0	6.0	--	Trask	(2)	(1939)
Holocene seabed sediments	58.0	34.0	7.0	2.2	0.6	Zo Bell	(14)	(1944)
Catalina sea basin, off California (1,300 m deep)	66.2	21.8	5.3	4.2	2.5	Orr, Emery	(15)	(1956)
Sediments of geological ages (1)	64.0	23.0	9.0	4.0	—	Trask	(2)	(1939)
Sediments of geological ages (2)	73.0	14.0	9.0	0.9	0.3	Zo Bell	(14)	(1944)
Oil shale	77.6	9.5	9.6	2.6	0.7	Orr, Emery	(15)	(1956)
Crude oil	85.0	0.5	13.0	0.4	0.1	Zo Bell	(14)	(1944)

(Taguchi, 1970)

ⓐ Hydrocarbons

As mentioned before, Smith succeeded for the first time in separating liquid (or rather paste-like) hydrocarbons from muddy sediments on the continental shelf of the Gulf of Mexico, triggering the theory of early formation of petroleum hydrocarbons. Later, Stevens, Bray, Evans and others examined hydrocarbons, which were treated as a bulk in a certain area by Smith, and separated them, comparing them with those in crude oil and sedimentary rocks. Through this investigation, they discovered notable differences in composition between them, and used this finding to prove the theory of petroleum origin in diagenesis. One difference lies in the occurrence *of n-porphyrin molecules with different carbon numbers*; viz., as Fig. 3.23 shows, in Holocene sediments, there are more molecules with odd number carbon atoms than those with even number ones. Bray and Evans gave the name of CPI (Carbon Preference Index) to this relative quantity ratio of odd-to-even numbers, and made it a comparison factor. In contrast n-paraffin in crude oil has no odd number preference; the CPI value is approximately 1, molecules with even and odd carbon numbers occurring at about the same rate. Sedimentary rocks can be divided into those with odd number preference and those in which molecules with odd and even carbon numbers are found in approximately the same quantity. Some researchers say that, in the former, maturation into petroleum has not progressed and the latter alone can constitute potential petroleum source rocks (Phillipi of the Shell group, Bray and Evans of Mobil Oil, etc.). One report states that Holocene sediments in deep seas have a CPI value of about 1 (Koons et al.).

The Cause of this would be that marine plankton having source organic matter (fatty acids) in which odd and even numbers were prone to become equal was predominant from the start, so that there was a difference from shallow-sea sediments in the quality of organic matter supplied.

With regard to low- to medium-molecule hydrocarbons (C_2 to C_{14}) which account for about 50% of crude oil, most of such hydrocarbons are lacking in Holocene sediments (Smith, 1954). Emery and Hoggen reported in 1958 that Holocene sediments in a sea basin off California contained only 1 ppm or less, if any, hydrocarbons of C_2 to C_{14}. Erdman et al. (1958) examined the aromatic hydrocarbons in Holocene sediments and showed that those from benzene to xylene were absent. Further in 1962, they pointed out that only C_1 and C_7 existed out of hydrocarbons of C_1 through C_8. In the same year Dunton and Hunt reported that their surveys on C_2 through C_8 hydrocarbons in Holocene sediments and old sediments (from the Tertiary period, Cenozoic era to the Precambrian age) in various places detected no hydrocarbon of C_4 and over but revealed that most C_2–C_8 hydrocarbons contained in crude oil were found in sedimentary rocks of geological ages older than Miocene. In Japan, too, this has been confirmed by the data of basic drilling by the Japan Petroleum Development Corporation.

As for C_{18} and higher hydrocarbons, Meinschein (1959) made detailed analyses and reported that isoparaffins and naphthenes in Holocene sediments are very similar to those in crude oil in terms of molecular weight distribution, and that much the same thing can be said of alkyl-benzenes, cycloalkyl-benzenes and naphthalenes. Concerning polycyclic aromatics with three or more condensed benzene rings, however, there is a difference between crude oil and Holocene sediments: alkyl aromatics are found in greater numbers in the former, whereas compounds without substituents are more numerous in the latter.

* * *

In summary, we may say that most petroleum hydrocarbons of C_2 to C_8 are not products direct from organic matter in living organisms, but have been formed only by undergoing the processes of geological ages. Also, heavy normal paraffins derive, to a great extent, from fatty acids constituting lipids in living organisms. Given the favorable conditions in geological ages, these paraffins undergo pyrolysis and repolymerizing reactions, yielding compounds in which odd and even carbon numbers are equal, or forming lighter hydrocarbons.

Meanwhile, there is a good chance that naphthalenes in crude oil stem from isoprenoids. As for lower aromatic hydrocarbons, it is difficult to seek directly related components in living organisms. As Erdman suggested (1961), they are thought to have been formed by cyclization of xanthophyll and carotenoids with conjugate double bonds (both found in algae), by dehydrogenation of terpenoids (also contained in algae in considerable quantities), by bond replacement, and other processes. In any event, organic substances contained in Holocene sediments cannot be changed into petroleum as they are. It is believed that they were turned into petroleum hydrocarbons only after being subjected to thermal action in the processes of geological ages.

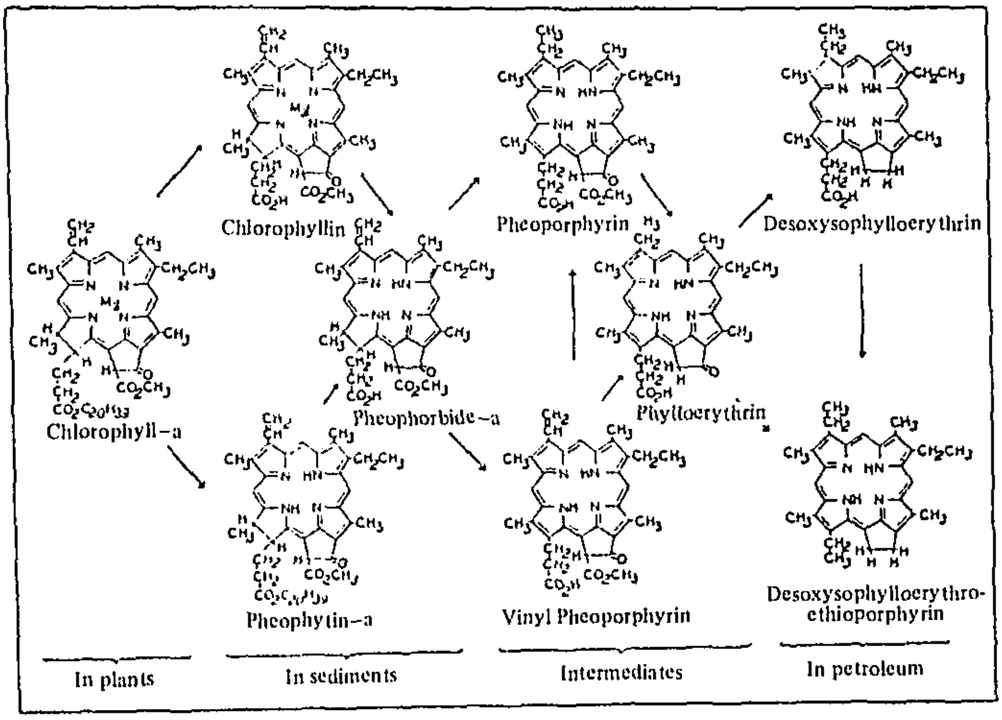
ⓑ Nonhydrocarbon components

Holocene sediments contain unexpectedly large quantities of substances that resemble asphalt components in crude oil. Erdman, on the basis of X-ray diffraction and infrared absorption spectrum analyses, deduced that asphalt was something like a sheet composed of fused aromatic rings with alkyl radicals attached to them. He argued that these fused rings originated from cellulose, and a matrix such as alkyl radicals from lignin. This deduction seems to be reasonable in the light of similarity in molecular structure, although a few questions remain unsolved.

As for porphyrins contained in crude oil, it is thought that chlorophyll and haemin which are universally present in living organisms are their precursor. In Holocene sediments, a predominant portion is accounted for by pheophorbide, which is formed by a process in which chlorophyll has its phytol group removed by hydrolysis, and further has its magnesium removed (Fig. 3.24). The compounds in crude oil and sedimentary rocks have extremely simple structures, such as desoxysophylloerythroethioporphyrin shown in the same figure. Emery showed the possible chemical changes involved in forming porphyrins as in Fig. 3.25. These changes include hydrogenation, hydrogen transfer, hydrolysis, decarbonization and other reactions. To porphyrins found in crude oil and old sedimentary rocks, nickel or vanadium oxide (VO) is attached instead of the magnesium of chlorophyll, presumably because of the high complex salt content depending on ion size, which may have caused the substitution to take place at a comparatively early period (some time possible under the solution theory).

Next let us discuss the capacity of conversion from organic matter in Holocene sediments to petroleum.

Fig. 3.25 Chemical Changes from Chlorophyll to Porphyrin in Crude Oil



—Nature of chemical changes involved in forming porphyrins found in petroleum from chlorophyll a. Intermediates selected to show changes in single steps (see text).

(2) Capacity of conversion to petroleum compounds

ⓐ Bacterial actions

It is surmised that bacterial activity was most vigorous in the early period of sedimentation. Zo Bell (1947) pointed out on the basis of the results of numerous experiments that anaerobic bacteria, which are considered to be related to petroleum formation, ① form hydrogen and contribute to the hydrogenation of unsaturated compounds, ② form methane from organic matter, ③ reduce sulfates to hydrogen sulfide and elemental sulfur, ④ act as a decarbonizer of organic acids, ⑤ generate various gases, and desorb oil adhering to sediments, thereby promoting the mobility of oil. Such actions are well expected in the early period of sedimentation, and have been supported by many positive research and experimental data. One may even say that the organic substances in Holocene sediments are products of bacterial actions.

ⓑ Thermal action

As sedimentation proceeds, sediments are hardened and reorganized by compacting action, their temperature rising little by little. It has been mentioned before that the ground temperature gradients in the basins where sedimentation is in progress average 1°C/33 m. Although this does not mean paleo-geotemperature itself, it can serve as a guide. A temperature of 100°C, for instance, is expected at a depth of 2,500 to 3,000 meters underground.

Abelson (1963) made the following proposition: the removal of phytol from porphyrin (hydrolysis) takes place at a comparatively low temperature in an early period – this is proved by the existence of pheophorbide in Holocene sediments as mentioned in the preceding section. On the premise that decarboxylation took quite a long time (probably more than millions of years) as well as a considerably high temperature, he tried to find the missing link between pheophorbide and desoxysophylloerythroethioporphyrin (the part to be filled by intermediates which have not actually been observed in nature). He pointed out that the conversion from chlorophyll to porphyrin in petroleum holds an important key, as it means the possibility of hydrogenation of kerogen and lipids, and decarboxylation. He goes on to say that this possibility is governed by thermal conditions, judging from experimental proof, and that this reaction is a first-order reaction of Arrhenius. The equation of first-order reaction of Arrhenius is as follows:

$$-\frac{dC_A}{dt} = K \cdot C_A, \quad K = S \cdot \exp\left(-\frac{E}{RT}\right)$$

where C_A : Concentration of substance A
K : Coefficient of reaction velocity
S : Arrhenius factor (frequency factor)
E : Activating energy
R : Gas constant
T : Absolute temperature

S is usually 5×10^{13} sec^{-1}. The important point is activating energy E; E required for decarboxylation is 30 to 50 k cal/mole, varying depending on the positions of carboxyl groups (–COOH). Assuming 40 k cal/mole and a temperature of 50°C, decarboxilation can take place well in a period of million year order. For fatty acids, it is experimentally known that E is 40 to 50 k cal/mole. Therefore, assuming 50 k cal/mole and 50°C, about 65% of decarboxilation is completed in about a million years. Now with regard to cracking of carbon-carbon combinations, assuming an E value of 58 k cal/mole according to experimental data and a temperature at 121°C, cracking of only 10^{-5} moles is attained in the time length of million year order. As the equation of coefficient of reaction velocity indicates, temperature is an influential factor, a rise of 10°C causing the reaction velocity to be approximately doubled.

Abelson also shows by inverse calculation that in order for large quantities of low-molecular hydrocarbons to exist in petroleum stemming from sedimentary rocks 100 million years old, the temperature then must have been about 60°C. However, this calculation disregards the catalytic action of clay minerals and other substances.

Erdman also (1961) placed emphasis on temperature conditions. He found that, when a dilute solution of carotin was heated in an experiment to produce aromatic hydrocarbons from unsaturated compounds with conjugate double bonds, the reaction proceeded in a rate-determining manner at 170° temperature, forming toluene, m-xylene, 2, 6-dimethyl naphthalene and other aromatic hydrocarbons.

As abovementioned, temperature conditions are very important and are thought to have played a leading part in the formation of petroleum hydrocarbons. It is presumed that, while bacteria were active in low-temperature and solution-theoretic reactions at the initial stage of sedimentation, thermal reaction went into operation after ground temperature began to rise gradually in parallel with commencement of diagenetic sedimentation and the sediments have concreted to some extent, whereby the conditions for solution-theoretic reaction have almost been brought to closure.

ⓒ Catalytic actions

Brooks (1958) experimentally proved that almost all acidic silicate minerals effectively catalyze various reactions of petroleum hydrocarbons, and that even if wet, they can play their part as catalyst though slowly. The most effective minerals are clay minerals such as montmorillonite, and he used fuller's earth. Protons are produced in the lattice and the silicate mineral acts as an acid-type catalyzer. For example, such reactions as cyclization, transfer and separation are performed through the formation of carbonium ions, which can be an extremely powerful assistant to thermal actions.

In the above we discussed three principal actions involved in the formation of petroleum. Some researchers claim that radioactivity also plays a part. However, we omit this factor as we do not think, after comprehensive studies, that it could have played so important a part. Muddy sediments with a large organic content change into petroleum to some extent and form intermediates in the initial stage of sedimentation owing to bacterial actions. As sedimentation proceeds, the sediments, under compacting forces, gradually assume the potential as petroleum source rocks. At a certain period of progress of sedimentation, hydrocarbons and intermediates thus formed migrate to reservoirs with water flow forced by compaction and accumulate therein. The organic substances left then in lutaceous rocks further form diverse petroleum hydrocarbons through heat and catalytic action. Migration from the source strata to reservoirs by water flow by compaction continues for some time, but when the source strata themselves have become concrete driving force of water flow by compaction can no longer be expected. In this period, internal pressure caused by the self load of rocks increases. Thus it is presumed that, through fissures made by such pressure and cracks formed by change of crystals of clay minerals etc., petroleum will migrate. The difficulty in evaluating petroleum source rocks lies in the necessity of considering both the time of petroleum formation and that of its migration as they are related to each other.

3.8.3 Migration, Accumulation and Disappearance of Deposits

Formation of a petroleum deposit requires accumulation of petroleum in a trap.

As stated in the preceding section, the manners in which petroleum is formed in the period from the initial stage of sedimentation of sedimentary facies destined to become petroleum source rocks to a period in geologic time scale seem to follow complicated processes with the passage of time. Therefore the processes of migration and accumulation are fraught with further complicated questions.

Although there are many theories, they are still in the stage of hypothesis; none of them are established.

Here we will comment on the theory which is considered to be best founded among them.

Migration from petroleum source rocks to reservoir rocks is generally referred to as primary migration, and that within reservoir rocks is called secondary migration.

(1) Primary migration

It is considered that after hydrocarbons were formed from sedimentary organic substances, part of them dispersed in water in a water-soluble or possibly colloidal state, and then entered reservoir rocks to become petroleum. The process in which sediments expel moisture by sedimentation pressure and turn solid is called the compaction process.

Hedberg (1963) divides this process into the following four stages:

i) The stage of up to 10 m sedimentation depth:
Porosity (equivalent to moisture content) decreases from 90% to 75%. At this stage, it is thought, mechanical adjustment of deposited particles takes place and water is exchanged freely between the sediments and the hydrosphere.

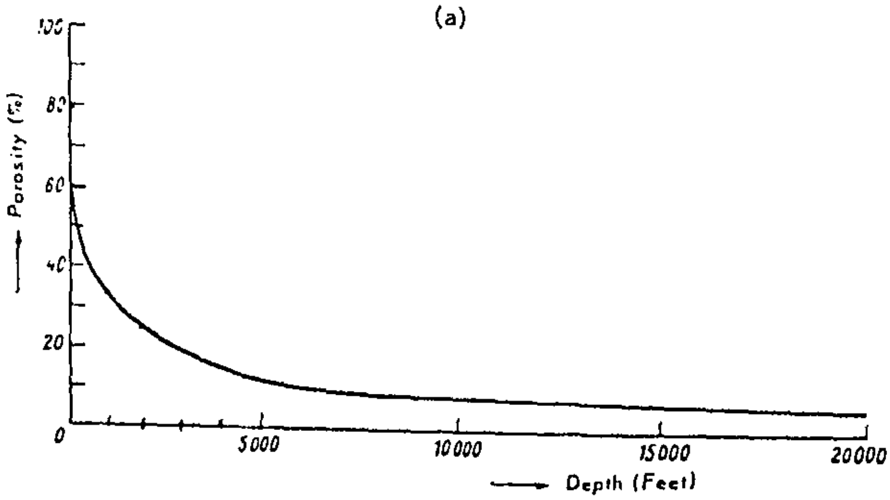
ii) The stage of 200 to 300 m sedimentation depth:
Porosity decreases from 75% to 35%, or to the extent that swollen clay mineral particles adhere to each other. Free water is very little. Since the water is shut off from the hydrosphere, an environment of strong chemical reduction prevails.

iii) The stage of 300 to 2,000 m sedimentation depth:
Porosity decreases from 35% to 10%. At this stage, mechanical deformation of deposited particles proceeds to a considerable extent.

iv) The stage of 2,000 to 3,000 m sedimentation depth:
Porosity drops to 10% or below. Compaction rate slows down extremely. As is illustrated in Fig. 3.26a, at a depth of about 3,000 m, porosity reaches 8%. At this point in time, rocks are recrystallized. Most of the water is adsorbed water and lattice water.

This theory of Hedberg's is based on the results of analysis using drill cores of shale in Venezuelan oil fields, and is thought to have general application in most cases. On compaction of clay, there are reports by Hedberg (1926), Athy (1930), Dickinson (1953), and Hosoi (1963), each based on experiments and data of field surveys. (Refer to Fig. 3.26b)

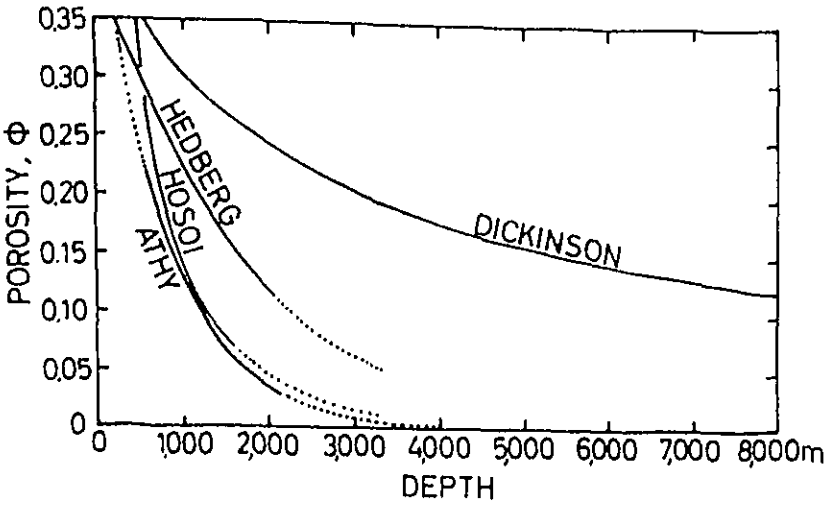
Fig. 3.26 Relationship Between Sedimentation Depth and Porosity in Lutaceous Sediments



(Hedberg, 1936)

(b)

COMPACTION AND MIGRATION OF FLUIDS IN MIOCENE MUDSTONE



.—Comparison of depth-porosity relations in several regions: Athy (1930), Oklahoma; Hedberg (1936), Venezuela; Dickinson (1951), Gulf Coast; Hosoi (1963), Japan.

(Mahei, 1968)

For Athy's curve in Fig. 3.26b, Rubey and Hubbert (1959) gave the following equation:

$$f = f_0 \cdot e^{-cz} \quad \text{①}$$

where f : Porosity at sedimentation depth z
f_0 : Porosity at initial stage of sedimentation
c : Coefficient (1.42×10^{-3}/m)

More recently Chapman (1972), introducing factor δ, proposed rewriting Equation 1 as follows:

$$f = f_0 \cdot e^{-c \cdot \delta \cdot z} \quad \text{②}$$

The factor δ is fluid expulsion function and is expressed by:

$$\delta = \frac{1-\lambda}{1-\lambda c}$$

where λ is the ratio of fluid pressure to overburden pressure, and λc shows the value of λ in equilibrium. In a special state where stress equilibrium is maintained between fluid and solid in clay (namely in a normal state of stationary fluid pressure), δ equals 1, and Equation ② coincides with Equation ① given by Rubey and Hubbert.

The quantity of expelled fluid in the compaction process can be regarded as the difference between the initial and compacted volumes of sediment and the solid component varies as the difference between the initial porosity and porosity under compaction, where the volume of solid component is maintained constant. The quantity of expelled fluid, $\hat{q}$, is given by the following equation:

$$\hat{q} = f - \frac{f}{1^{0} - f} \cdot (1 - f_0) = \frac{f_0 - f}{1 - f} \quad \text{③}$$

When Equation 1 is substituted into Equation ③, we get

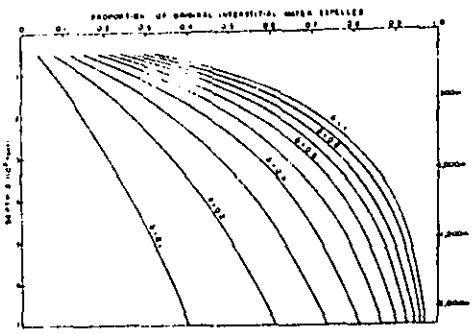
$$\hat{q} = \frac{f_0(1 - e^{-c\delta z})}{1 - f_0 e^{-c\delta z}} \quad \text{④}$$

The ratio of expelled fluid to initial interstitial fluid is:

$$\hat{q}/f_0 = \frac{1 - e^{-c\delta z}}{1 - f_0 \cdot e^{-c\delta z}} \quad \cdots\cdots\cdots\cdots ⑤$$

Fig. 3.27

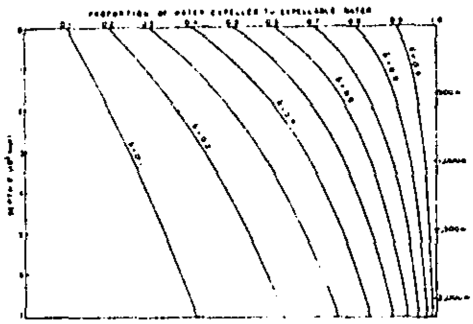
(Chapman, 1973)



—Relations between proportion of initial interstitial liquid expelled, depth, and δ.

Fig. 3.28

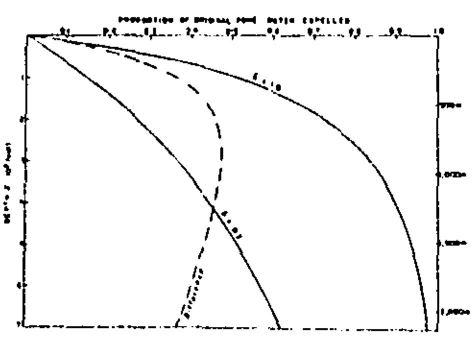
(Chapman, 1973)



—Ratio of liquid expelled to liquid that would have been expelled under equilibrium conditions, and its relations with depth and δ.

Fig. 3.29

(Chapman, 1973)



—Comparison between proportions of initial interstitial liquid expelled from normally pressured and abnormally pressured clays during burial.

A graphic representation of the variation of this ratio in relation to the variation of δ within the depth range in Athy's compaction curve is given in Fig. 3.27 (in which f_0 is given a value of 0.43 following Athy's experiment). As this figure shows, the higher the interstitial fluid pressure, the greater the quantity of fluids remaining in the pores of the sediment (in particular, clay).

The ratio of $\hat{q}$ to $\hat{q}_e$, which is the expelled quantity when fluid pressure and overburden pressure are in equilibrium, is given by the following equation:

$$\hat{q}/\hat{q}_e = \frac{f_0(1-e^{-c\delta z})/(1-f_0 \cdot e^{-c\delta z})}{f_0(1-e^{-cz})\ /(1-f_0 \cdot e^{-cz})}$$

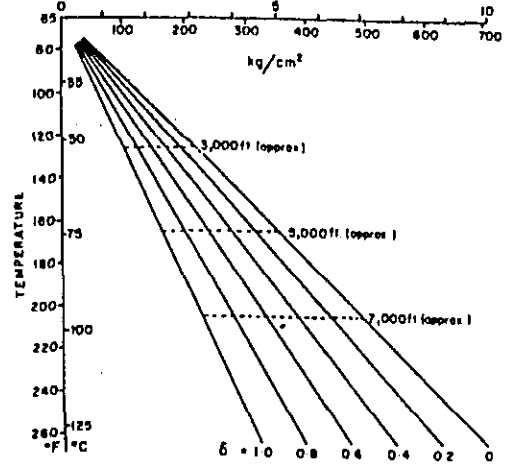
$$= \frac{(1-e^{-c\delta z})(1-f_0 \cdot e^{-cz})}{(1-e^{-cz})(1-f_0 \cdot e^{-c\delta z})} \quad \cdots\cdots\cdots\cdots ⑥$$

When the value of δ is 1, fluid pressure is stationary, and when δ approaches 0, fluid pressure approaches overburden pressure. Equation ⑥ is illustrated in Fig. 3.28.

In this figure, when the expelled quantity $\hat{q}$, at a depth of 7,000 ft (2.135 m) is calculated by assuming an average δ value of 0.2 ($\lambda = 0.9$), it will be found that 60% of initial fluids is expelled and 40% remains. Fig. 3.29 shows a comparison between cases where the δ value is 0.2 and 1 at various depths. From this, it is seen that the difference between the two cases is maximum at a depth of about 3,000 ft (≒ 1,000 m). This corresponds to what Weeks (1958) said: petroleum occurs mostly at a sedimentation depth of 2,500 to 9,000 ft (≒ 750 to 2,700 m).

Now let us examine the influence of temperature. When we assume a certain unit of clay for which gravity is the only compaction force, in a state where there is practically no disappearance due to stress equilibrium, the stationary fluid pressure gradient will be subordinate to geothermal temperature. However, the fluid pressure about the center of the mass of clay approaches the overburden pressure and, at a δ value of 0.2, will become about double the stationary fluid pressure. From Figs. 3.29 and 3.30, the following is surmised: Under equilibrium conditions (when $\delta=1$) 50% of the initial fluid remains in compacted clay at a sedimentation depth of 1,000 ft (about 300 m). From the average geothermal gradient, the temperature of this fluid is estimated at about 85°F (≒30°C), and consequently the pressure will be about 32 kg/cm^2. At a δ value of 0.2, then, 50% of the initial interstitial fluid will remain in the clay until the sedimentation depth reaches about 5,000 ft (≒1,500 m), where geothermal temperature is approximately 160°F (=70°C) and the pressure is about 4,300 psi (≒300 kg/cm^2).

Fig. 3.30



—Temperature-pressure field during burial and compaction. In this figure, geothermal gradient has been taken as 20°F/1,000 ft (36°C/1,000 m), the normal hydrostatic gradient as 460 psi/1,000 ft (106 kg/sq cm per 1,000 m) and λ_e as 0.46.

Now if one is to make a quantitative evaluation of the velocity of fluid expulsion from a sediment (let us say clay), one must take into consideration the variation of permeability of compacted clay. Regarding this problem, one must go into the theory of field of flow, namely, the problem of field based on Darcy's law. Hubbert (1953) cleverly summarized this problem of field of flow.

ⓐ Field of flow

Apart from energy or force, let us hydromechanically consider the flow of ground water passing a porous rock saturated with water in underground space. For this purpose we will consider a certain section viewed broadly in comparison with granularity and pore size of rock, and take a macroscopic viewpoint whereby that geometrical quantity is grasped as a statistical quantity. In a space where water flows, the flow has a certain direction at a given point and at a given time. The lines drawn over the whole field tangential to the direction of flow at each point include the family of flow lines of the system. The ratio of flow at a given point is defined as water quantity (ΔQ) in a unit time for a unit sectional area (ΔS) at right angles to the flow direction; it is referred to as specific discharge at that point and is given in volumetric ratio. When it is expressed in flow vector q, the following equation is given:

$$q = \lim_{\Delta s \to 0} \frac{\Delta Q}{\Delta S} \quad \cdots\cdots\cdots\cdots ⑦$$

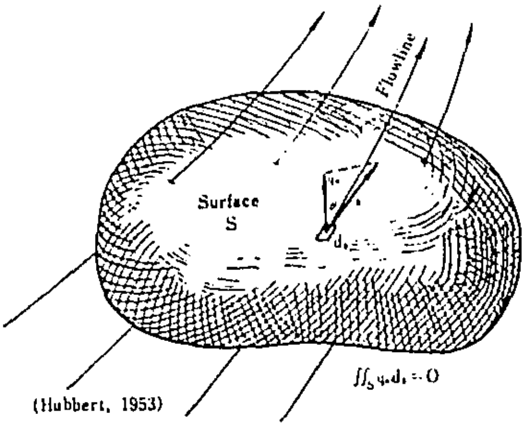
Hence, field of flow can be expressed by a family of flow lines which are tangential at all points to vector q of specific-volume discharge. The only hydromechanical condition to be met by this field is that it follow the law of conservation of matter.

Now, with regard to a sedimentary rock, we set forth a completely enclosed spherical surface S. And if fluid passes a part of the spherical surface and enters pores enclosed by S, the same quantity of fluid has to go out of the spherical surface at the same time. The quantity dQ that passes the part of the spherical surface, dS, and is discharged in a unit time is expressed as follows:

$$dQ = q_n \cdot dS \quad \cdots\cdots\cdots\cdots ⑧$$

Here q_n is a component of the flow vector acting perpendicular to dS (n). Hence, the net discharge (Q) over the whole surface is given by the following equation:

Fig. 3.31 Schematic Diagram to Show that the Total Net Discharge Going Out of the Whole Surface S of a Closed System is 0.



(Hubbert, 1953)

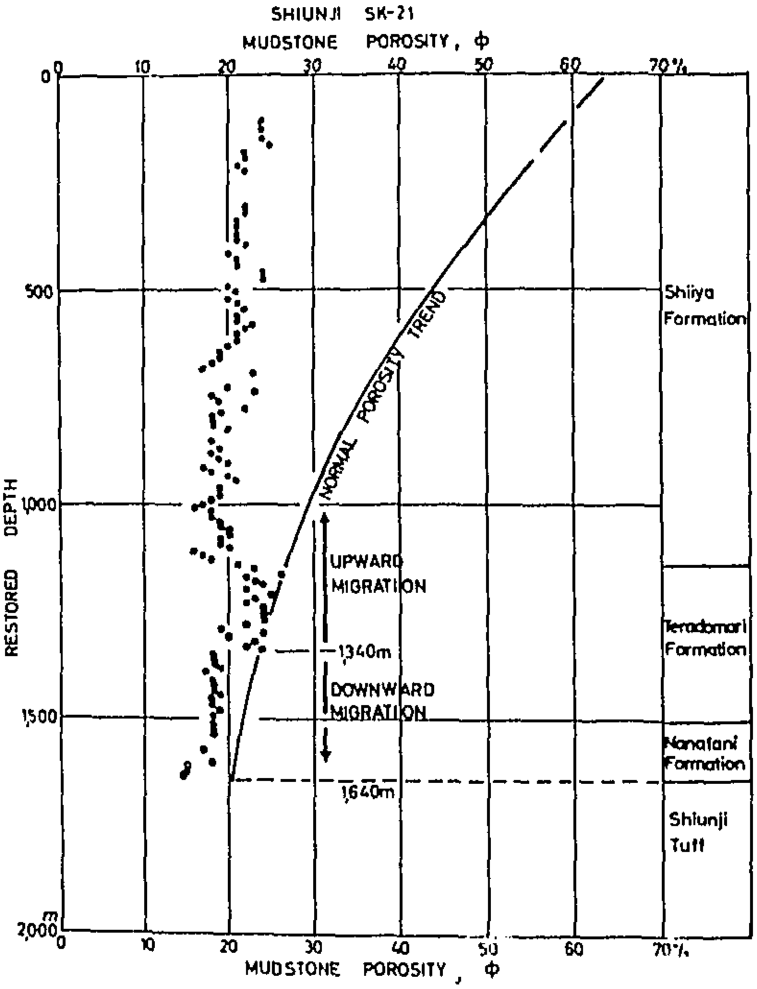
$$Q = \int dQ = \iint_S q_n \cdot dS = Q \quad \text{.............} ⑨$$

(See Fig. 3.31)

Magara (1968) closely analyzed well data (status of oil production, Δt·sh–log and other various logging data) of several oil-gas fields of Japan (Shiunji, Kumoide, etc. of Niigata Prefecture), and proposed the idea of down-migration based on abnormal variation of porosity in mudstone (Fig. 3.32). It is worthy of note that such fluid migration under compaction can actually occur in the downward direction as well as in the vertical or lateral direction.

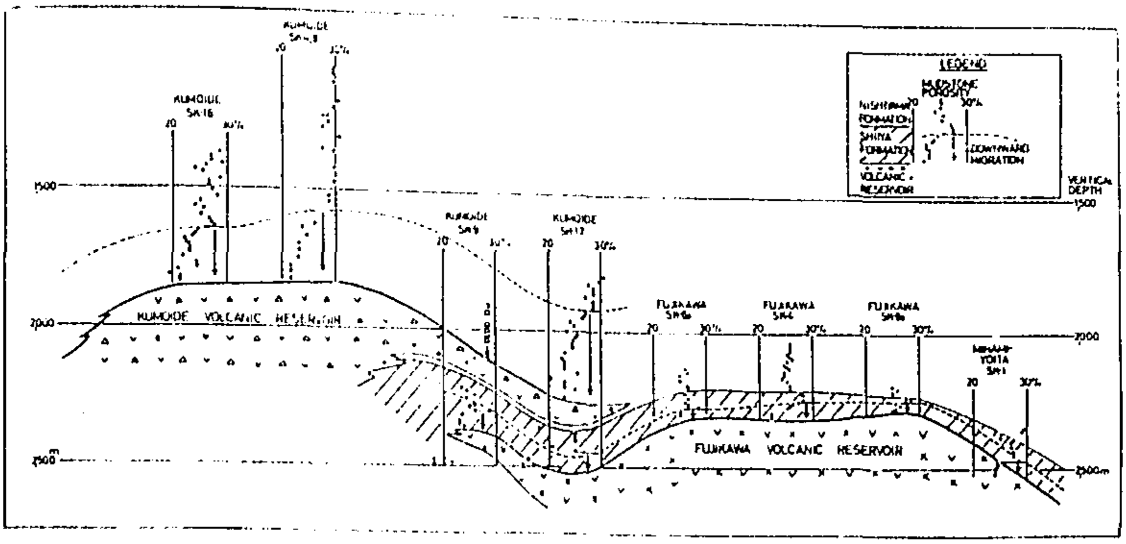
Migration of expelled fluids takes place isothermally in the direction from abnormal pressure to hydrostatic pressure along the fluid potential gradient. This was explained in detail by Hubbert (1953).

Fig. 3.32 (a) (KINJI MAGARA, 1969)



—Reconstruction of formations at end of Shiiyan Stage and mudstone-porosity plot of Shiunji SK-21.

Fig. 3.32 (b)



--Vertical porosity distributions of mudstone in Fujikawa-Kumoide trend. (真柄, 1969)

Ⓑ Theory of groundwater potential and field of force

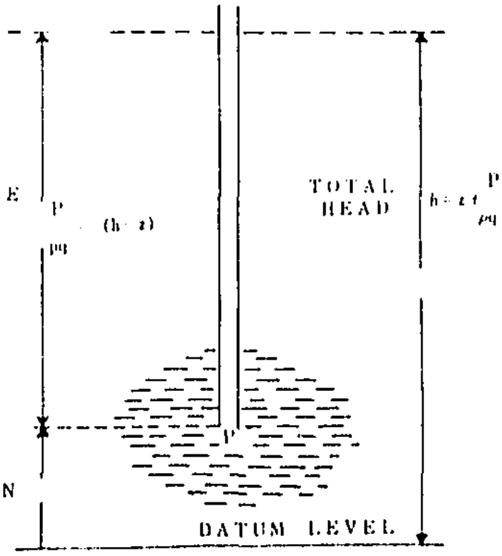
Fluid potential (Φ) expressed in the basic equation of hydromechanics is:

$$\Phi = g \cdot z + \frac{P}{\rho} = g \cdot z + \frac{\rho \cdot g(h-z)}{\rho} = g \cdot h \quad \text{.................................} \quad ⑩$$

where
g : Gravity
z : Height of a given point from sea level
ρ : Fluid density
P : Pressure of fluid at z
h : $z + P/\rho g$

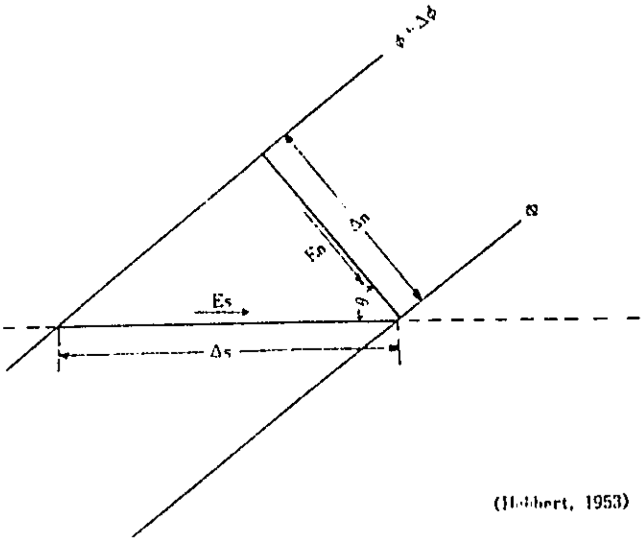
That is to say, the value of Φ equivalent to the work required to lift a unit mass of fluid in a given place to height h (Fig. 3.33). Since Φ is a function of the variables z and P, a group of

Fig. 3.33



surfaces where P varies continuously and Φ is constant is formed. Potentials of two of the surfaces are taken as Φ and Φ + ΔΦ, and the vertical distance between the two surfaces as Δn. ΔS is taken as the incline distance between the two surfaces forming angle θ to the vertical direction, and the vector E of unknown magnitude and direction is taken as the force acting on a unit mass of the fluid from around it (Fig. 3.34). The energy required to move a unit mass fluid from the surface of potential Φ to the surface of Φ + ΔΦ is equal to ΔΦ irrespective of route. This energy is negative to a component of E.

Fig. 3.34



(Hubbert, 1953)

$$\Delta\Phi = -Es \cdot \Delta S = -En \cdot \Delta n$$

Therefore

$$En = -\frac{\Delta\Phi}{\Delta n}, \quad Es = -\frac{\Delta\Phi}{\Delta S}$$

where $\Delta S = \Delta n / \cos\theta$, so that

$$Es = En \cdot \cos\theta \quad \text{.........} \quad ⑪$$

The above follows the laws of vector analysis, and En is equal to unknown vector E in both direction and magnitude. Therefore, En acts on mass points of fluid from around it. The force acting on unit mass is perpendicular to the equipotential surface and in a direction of potential decrease. This is expressed as follows:

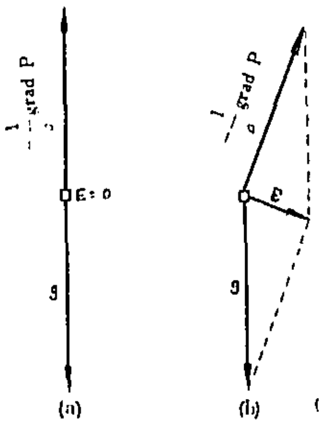
$$E = -\frac{\Delta\Phi}{\Delta n} = -\mathrm{grad}\Phi = -g \cdot \mathrm{grad}\, n = g - \frac{1}{\rho} \cdot \mathrm{grad}\, P \quad \text{.........} \quad ⑫$$

The component of E in a given direction is:

$$Es = -\frac{\partial\Phi}{\partial S} = -g \cdot \frac{\partial n}{\partial S} = g \cdot s - \frac{1}{\rho} \cdot \frac{\partial P}{\partial S} \quad \text{.........} \quad ⑬$$

When a fluid is placed at all points of a space where fluid potential is not constant, force E acts on unit mass there and drives the fluid in a direction of potential decrease. Conversely, when no such force acts, the fluid tends to assume a hydrostatic equilibrium. At that time,

Fig. 3.35



(Hubbert, 1953)

$$E = -\text{grad}\,\Phi = 0 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{⑭}$$

Throughout such a whole area,

$$\Phi = g\cdot z + \frac{P}{\rho} = gh = \text{const.} \quad \ldots\ldots\ldots\ldots \text{⑮}$$

Also, since

$$\text{grad}\,\Phi = g - \frac{1}{\rho}\text{grad}\,P = 0$$

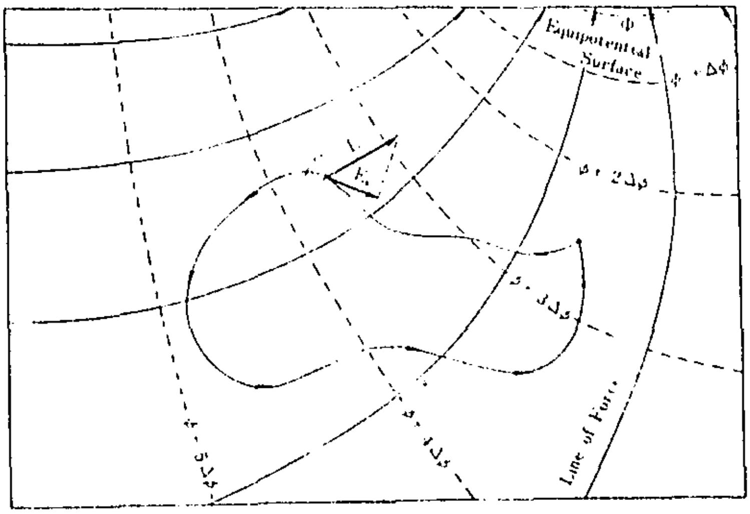
$$\frac{1}{\rho}\text{grad}\,P = g \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{⑯}$$

is obtained.

The physical meaning of Equation ⑫ , $E = g - 1/\rho\cdot\text{grad}\,P$, is expressed in Fig. 3.35: (a) shows a hydrostatic case ($E = 0$), (b) a hydrodynamic case.

In general, at a point occupied by fluid, vector E has a certain value. Throughout the whole, the total of such values is referred to as field of force. If lines tangential to E are drawn at all the points, a group of lines of force expressing the field can be obtained (Fig. 3.36).

Fig. 3.36



(Hubbert, 1953)

Based on the above theory, we cannot always say that vertical migration plays the leading part and lateral migration takes place only occasionally. Depending on the conditions of the field of sedimentation, downward migration is naturally possible.

It is generally said that petroleum accompanying expelled water in the compaction process cannot participate in a deposit unless the sedimentation depth is at least 2,000 ft (about 600 m). Cited as the grounds for this are: ① the sedimentation depth of deposits where accumulation is now taking place, ② relationships between overburden pressure and fluid pressure, ③ connections with the time of trap formation, ④ relationships of overburden pressure with gas-saturation rate of petroleum.

Gussow (1954) argues that in order for overburden pressure to flush oil globules, it has to exceed capillary pressure, so that a sedimentation depth of 2,000 to 3,000 ft is needed. Power (1967) observes that unless interstitial water of montmorillonite (a clay mineral with a swelling property) is expelled to a considerable extent, a petroleum-like substance (with a certain polarity) readily adsorbable on clay grains cannot be taken out, and a sedimentation depth of at least 1,500 to 3,000 ft is required before the expulsion of water can take place. Since this problem has a very important meaning particularly to deposits originating in petroleum source rocks of lutaceous rocks, many researchers have studied it. Recently Cordell (1973) reviewed and summarized this problem on the basis of available data. His conclusion is that the sedimentation depth required is 3,000 to 3,500 ft.

Now let us go into the question of what phases were assumed by petroleum in primary migration.

Table 3.15 Solubility of Hydrocarbons in Water

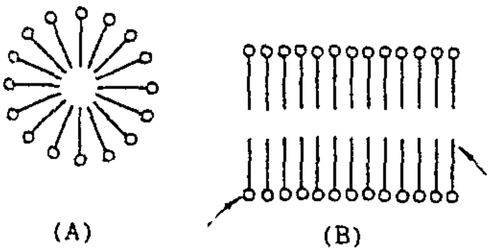
	ppm (w/w)
n − Pentane	3885 ±2.0
n − Hexane	9.5 ±1.3
n − Heptane	2.95±0.20
n − Octane	0.65±0.06

(McAuliff, 1963)

	ppb (w/w)
n − Decane	22
n − Octadecane	7.75
n − Hexatriacontane	0.29

(Baker, 1959)

Fig. 3.37 Types of Micelles



a : Hydrophylic end
b : Hydrophobic end (Baker, 1962)

One of those is dissolution in water. The solubility of hydrocarbons is, as shown in Table 3.15, of the order of tens of ppm under atmospheric pressure in the case of very light fractions. The heavier hydrocarbons have a lower solubility; with normal decane ($n\text{–}C_{10}H_{22}$) it decreases to 22 ppb. As pressure rises, solubility increases of course, but total solubility must have been only 10 to 100 ppm in the light of data of stratum water.

Second there is the theory of micelle migration advanced by Baker in 1960. Micelles are colloidal particles whose structures are shown schematically in Fig. 3.37. Type (A) in the figure is a minute globule of ionic micelles; the oil phase (nonpolar) in enclosed in a surface active agent. Type (B) assumes a wafer-like configuration with neutral micelles and has an icing position structure. Distribution of these micelles is lognormal, clearly indicating that they are composed of two kinds. In mean value, the diameter of small globules is 6 mμ and that of large globules is 500 mμ. Small globules are composed of naphthenate ion micelles, and large ones of naphthenate neutral ion micelles. Baker says such micelles play an important part in the segregation of hydrocarbons. There are similar theories as follows:

Dunning and others (1957) stated that porphyrin acted as an effective surface active agent. Hodgson (1960) said, on the basis of many experimental data, that micelles of free type (without Ni or VO) are more polar than those forming complex salts with Ni or VO and strongly adsorbed on the surface of clay, while those of the complex salt type with weak polarity pass more freely between clay grains, and hydrocarbons forming colloids with these micelles are segregated and migrate with water. The hydrocarbons in a state of hydrophylic colloids thus formed occasionally dissolve in water at a high rate of more than 1,000 ppm (toluene, 1,500 ppm).

Mikami (1960), following Brooks (1958), regarded protopetroleum as an asphalt-like compound, and said that protopetroleum and substances that have not matured much into real petroleum are hydrophylic as they contain various polar substances; they are dispersed in water and undergo primary migration accompanying the flow of water under compaction. During their migration in sediments, they are converted further into petroleum and, losing polar substances gradually, they become more hydrophobic. Hence surface tension between petroleum and water prevents petroleum from entering the minute pores of lutaceous rocks, allowing only water to enter there; petroleum is thus "screened" and left in coarse pores of sand and the like.

This theory assumes that part of petroleum (the hydrocarbons already formed) and protopetroleum were expelled from petroleum source rocks by compaction and came into reservoir rocks in a comparatively early period of sedimentation (its depth was presumably more than 2,000 ft).

This theory is supported by the fact that asphaltic crude oil is accumulated in quantity in hinge belt zones particularly, among various traps of sedimentary basins.

In the above we described mainly primary migration from lutaceous sediments, but petroleum source rocks have another substance originating from living things and organic matter, namely, carbonates. Having an inclination toward early petrification, carbonates have no compaction mechanism. For this reason, they retain petroleum in source rocks until suitable migration paths are formed by fractures, fissures, dissolved channels, or recrystalization such as conversion into dolomite. In this respect, carbonates are subject to unfavorable conditions compared with lutaceous rocks.

(2) Secondary migration

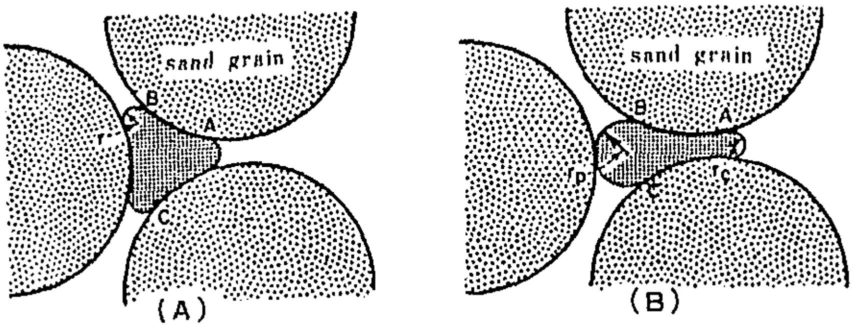
Here we shall see how petroleum which had entered reservoir rocks by primary migration and substances which, from the precursor of petroleum with strong polarity, had become considerably nonpolar and come to resemble petroleum in the process of primary migration were concentrated in reservoir rocks and came to form a continuous petroleum phase.

Migration in a phase with such coarse porosity and high permeability as are found in reservoir rocks is quite different from primary migration. Soluble hydrocarbons, colloidal petroleum and petroleum-like substances which have come into reservoir rocks are now in a position of low fluidity potential, so that part of gas will be released, colloids will be ruptured causing spots of petroleum, which will be gradually concentrated and become oil drops grown to a considerable extent. In such colloid rupture, salinity change due to dilution by rainwater and variation of pH occasionally play an important part.

Petroleum or small oil drops dispersed in a water-saturated, porous medium do not migrate in a state of hydrostatic pressure. Petroleum migrates only when buoyancy has increased—aided by addition of gas and enlargement of oil drops—sufficiently to overcome resistance to upward migration, or when the velocity of water migration is increased by considerable build-up of hydrodynamic force. Water-pressure gradient found in nature is in no way sufficient to start migration of dispersed petroleum. The first barrier to be overcome is the obstruction to capillarity around the oil-water interface; this is a question of whether capillary pressure can overcome the displacement pressure of larger pores or the displacement pressure of capillary tubes between pores. Levorsen has explained this in a comprehensible way.

Displacement pressure of pores is constant whether they involve petroleum-sand or water-sand. On the other hand, capillary pressure varies depending on buoyancy, hydrodynamic pressure and length of the continuous phase of petroleum. If capillary pressure overcomes displacement pressure with the aid of such forces, the oil-water interface enters capillary tubes which are a continuity of pores, through which petroleum migrates. To grasp this quantitatively, one must seek the difference of capillary pressure at the front end of migrating oil particles.

Fig. 3.38 Insular Petroleum Particle Undergoing Deformation Required for it to Pass Through a Barrier Between Pores



Geometry of a pore, showing the distortion that is necessary if an insular particle of oil is to be forced through a pore constriction.

(Levorsen, 1954)

Fig. 3.38 illustrates the shape of an insular oil particle in a pore when there is very little or no force to move the oil particle.

In Fig. 3.38, capillary pressure in (A) is expressed by the following equation:

$$Pc = \frac{2\gamma\cos\theta}{r} \qquad \text{⑰}$$

Since points A, B and C are all shown by the same radius of curvature, capillary pressure is approximately the same at the three points. (B) depicts a deformed oil particle immediately before moving to the adjacent pore to the right, forced through the constriction at point A. The capillary pressure in this state is shown as $Pc = 2\gamma\cos\theta/rc$ at the front end and $Pc = 2\gamma\cos\theta/rc$ at the rear end. Here rc means the effective radius of capillary tube between pores, and r_c that of the pore. The capillary pressure difference between the front and rear ends is:

$$\Delta Pc = 2\gamma\cos\theta(1/rc - 1/rp)$$

Assuming that the capillary radius, rc, between pores is 1/2 to 1/4 the pore radius, rp, the capillary pressure difference necessary for migration is: $\Delta P_c = 2\gamma\cos\theta/r_p \sim 6\cdot\gamma\cos\theta/r_p$. If $r_p=1/3$ is taken as the mean value, then $\Delta P_c = 4\gamma\cos\theta/r_p$, and if it is assumed that θ is 60°, then $\Delta P_c = 2\gamma/r_p$. Table 3.16 sets forth the results of calculations of the mean values of capillary pressure difference required for migration under these hypotheses, with regard to various interfacial tensions and pore sizes.

Based on the above hypotheses, let us discuss capillary pressure gradient necessary for migration. Assuming that petroleum exists in the form of insular oil particles in pores as in Fig. 3.38, and water flows horizontally to the right, capillary pressure difference is equal to the difference of pressure from one pore to the next. When the hydrodynamic gradient is 10 ft/mile, which is a level ordinarily seen, capillary pressure difference will be 0.1 dyne/cm^2 for coarse sand and 0.02 dyne/cm^2 for fine sand. Even at the steep hydrodynamic gradient of 100 ft/mile, capillary pressure difference will be only 1.0 dyne/cm^2 for coarse sand and 0.2 dyne/cm^2 for fine sand. Comparison of these figures with the capillary pressure difference necessary for petroleum migration indicated in Table 3.16 will show that a naturally occurring hydrodynamic gradient is too small to cause petroleum migration.

Neither is buoyancy sufficiently large to make insular oil particles move. A petroleum buoyancy of 30° API (0.87), $(\rho w - \rho o) \cdot g$ dyne/cm^2, will generate a capillary pressure difference of only 1.5 dyne/cm^2; a buoyancy thousands of times as large will be needed to cause petroleum

Table 3.16 Capillary Pressure Difference Necessary for Migration

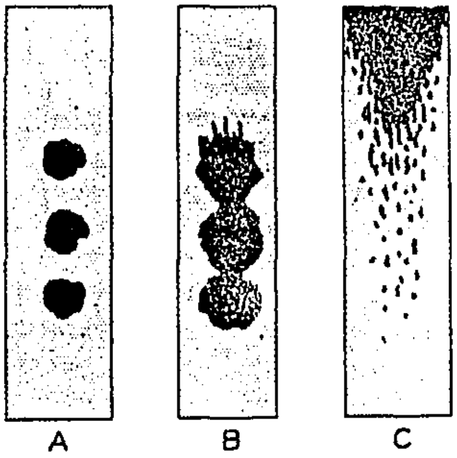
$$\Delta P_c = \frac{2\gamma}{r_p}$$

Pore Radius (cm)

Interfacial Tension	r_p = .02cm.	r_p = .01cm.	r_p = .005cm.	r_p = .002cm.	r_p = .001cm.
	Very Coarse Sand	Coarse Sand	Average Sand	Fine Sand	Very Fine Sand
30	3,000	6,000	12,000	30,000	60,000
25	2,500	5,000	10,000	25,000	50,000
20	2,000	4,000	8,000	20,000	40,000
10	1,000	2,000	4,000	10,000	20,000
5	500	1,000	2,000	5,000	10,000
1	100	200	400	1,000	2,000

(Levorsen , 1954)

Fig. 3.39 Experiment in Buoyancy (Hill, 1951)



migration as shown in Table 3.16. This means that such insular oil particles must make thousands of continuous phases. An example of experiment in buoyancy is given in Fig. 3.39. As soon as enough buoyancy to start migration has been created, the continuous phases grow larger, and buoyancy further increases, accelerating migration velocity.

Migration caused by capillary pressure will be limited to small-scale readjustment along the oil-water interface and to local redistribution of petroleum and water between the coarse-grain and fine-grain parts of a petroleum reservoir.

(3) Accumulation

The process of concentration, beginning from the state of petroleum dispersed in water in reservoir rocks and leading up to the accumulation of petroleum in a trap in a quantity worthy of working, is the final stage of deposit formation. This process is referred to as the mechanism of accumulation.

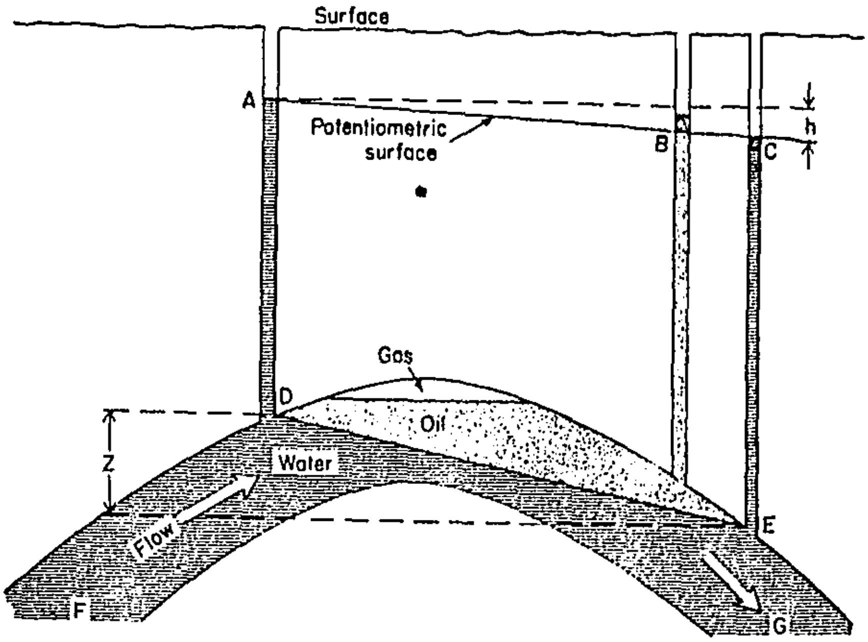
Since accumulation means the state of forming continuous phases of petroleum, it signifies migration in the strata of reservoir rocks, namely, a state of hydrostatic equilibrium of fluids at a given point in time in the secondary migration process.

Even if a hydrodynamic gradient exists, it is always lower than the hydrostatic gradient. A trap obstructs the lateral migration of oil and gas. Since a trap, even in continuous reservoir rocks, is located at a high level where hydrostatic pressure is lowest, it is also a place toward which buoyancy of oil and water acts. In terms of the potential energy theory, a trap means a low-energy position toward which petroleum in a high-energy position tends to move.

Until a trap is connected with a low-energy point, petroleum and gas remain in a state of equilibrium with physical conditions in the trap. The connection with a low-energy point is brought about by faulting, regional tilting, high hydrodynamic pressure in rocks, and a pressure decline caused by oil and gas exploitation through wells. For example, folds not only form a structurally high region locally, which has a low hydrostatic pressure, but also bring about a pressure decrease. This is explained as follows: if cataclasites are folded, bending of strata causes fractures, resulting in fine rearrangement of loosely cagulated particles. Thus the volume of pores in rocks is locally augmented.

There are many cases of petroleum deposits where oil-water contacts are sloped. Ordinarily the slope is several feet per mile, but occasionally it is more than 800 ft/mile, or 8° in inclination angle. The cause of this inclination has been explained variously but the best explanation would be to take it as a result of hydrodynamic gradient indicated by potentiometric surface. Where the potentiometric surface is horizontal, fluid pressure at all points in reservoir rocks is the same and the oil-water contact is also horizontal. However, in a place where the potentiometric surface is inclined, there is a hydrodynamic gradient in the direction perpendicular to the contour of the potentiometric surface, and water flows in rocks in the direction of inclination of the potentiometric surface (Fig. 3.40). In the figure this means that as the potentiometric surface, with a slope of dh/dl, is lower at G than at F, water flows in the reservoir from F to G. When the difference of specific gravity between petroleum and water decreases, the oil-water contact will incline sharper than the potentiometric surface. The direction of inclination is the same. Water flows, but petroleum remains in a state of stationary equilibrium. The inclination of the oil-water contact is:

Fig. 3.40



Diagrammatic section showing the relation of the slope of tl oil-water contact to the slope of the potentiometric surface.

(Levorsen, 1954)

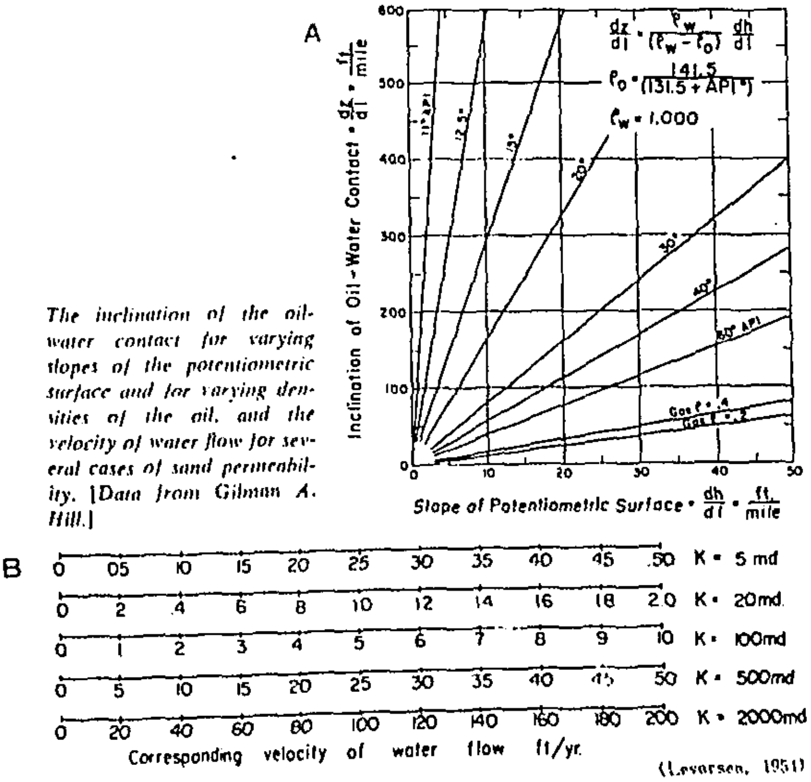
$$\frac{dz}{dl} = \frac{\rho w}{\rho w - \rho o} \times \frac{dh}{dl} \quad \cdots\cdots ⑱$$

where ρw : Density of water
ρo : Density of petroleum

If dh/dl (inclination of potentiometric surface) is known, the inclination of an oil-water contact can be sought by calculation. Fig. 3.41 a shows the inclination of the oil-water contact for various slopes of the potentiometric surface and for various densities of petroleum (API). B of the same figure shows the orders of velocity of water flow for various cases of sand permeability. This figure indicates that the inclination of the oil-water contact is steeper with petroleum of lower API than with that of high API. This can be explained by a vector diagram as shown in Fig. 3.42.

The time of accumulation is usually determined by applying the law of gases, or Boyle-Charles' law. According to this law, the colume of gas is proportional to absolute temperature and inversely proportional to pressure. The effect of temperature can be disregarded in dealing with this problem, because it is considerably smaller than the effect of pressure under the pressure-temperature gradient usually encountered in oil fields. The law of gases can be applied as follows: the volume of gas accumulated in a trap varies subject to pressure. This means that, in a trap completely saturated with gas, the gas accumulation as at present was attained only after the present pressure at least had been realized. Assuming, for example, a temperature of 60°F and a pressure of 1 atmosphere (14.7 psia) at the time of accumulationin an oil reservoir, and using the state then as the standard, we find that gas volume decreases owing to an increase in oil reservoir pressure caused by subsequent burying of the reservoir, while it increases with a rise in temperature. The pressure increase reduces the gas volume to a fraction of the original volume. For instance, the volume of gas under the conditions of 153 atmospheric pressure (2,250 psia)

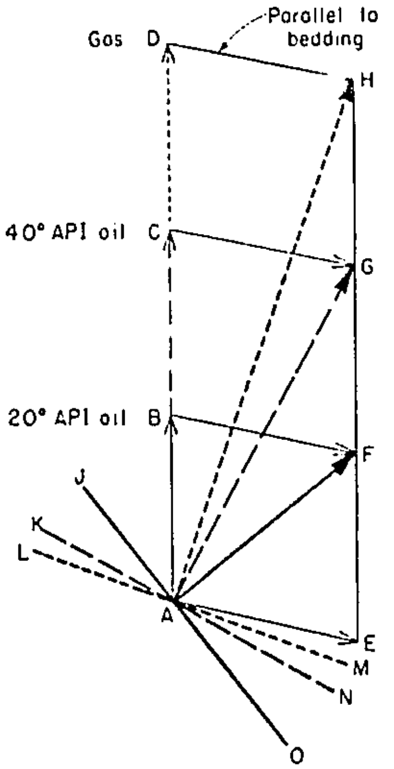
Fig. 3.41



The inclination of the oil-water contact for varying slopes of the potentiometric surface and for varying densities of the oil, and the velocity of water flow for several cases of sand permeability. [Data from Gilman A. Hill.]

(Levorsen, 1951)

Fig. 3.42



Vector diagram showing the effect of the same hydrodynamic force on different petroleums. The hydrodynamic force is shown as vectors parallel to the bedding (BF, CG, *and* DH) *for oils of 20° and 40° API gravity and for gas, respectively. The buoyancy force is represented by a vector directed vertically upward; its magnitude varies with the magnitude of the difference between the densities of the given petroleum and water. The greater the difference in density, the greater the buoyancy force. Thus the buoyancy vector for gas (80° API) in a water system is represented by* AD, *the vector for 40° API oil as* AC, *and the vector for 20° API oil as* AB. *When these buoyancy force vectors are combined with the hydrodynamic force vectors,* BF, CG, *and* DH, *the vectoral sums become* AF, AG, *and* AH, *respectively, for the 20° and 40° oils and the 80° gas. The oil-water contacts are normal to the vector sums* AF, AG, *and* AH *and are shown as the slopes* JO, KN, *and* LM, *respectively.*

(Levorsen, 1967)

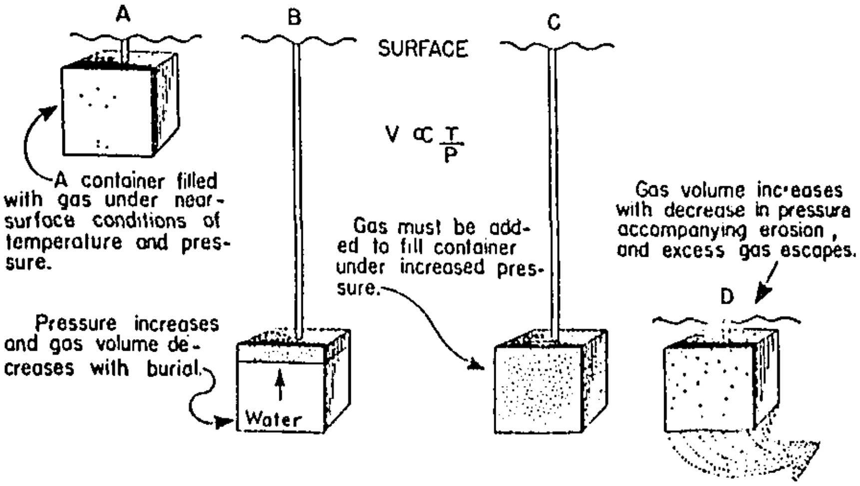
and 160°F, which are equivalent to the pressure and temperature usually prevailing at a depth of 5,000 ft, is approximately 1/143 the volume under surface conditions. However, if pressure is low the volume of gas which a trap can actually hold is small, so that it must have been after the pressure reached 143 atmospheric pressure that all of the gas accumulated at present in a trap entered the trap. The gas-holding capacity of a trap increases with pressure. In other words, we may say it is in direct proportion to the oil reservoir pressure.

In conclusion, it was only after the burying depth had reached 5,000 ft that all of the gas now filling the trap entered it. Conversely, in order for a trap to remain filled with gas, gas must migrate to the trap as pressure increases with burying. Fig. 3.43 shows a model of application of this theory to gas of unit volume.

A way to explain the variation of the volume of petroleum and gas in neighboring traps was proposed by Gussow (1953). This is the theory of differential entrapment, which will be described below:

For example, when a fold-type trap is filled with petroleum and gas, and more petroleum and gas are added into the trap or the volume of gas increases owing to a pressure drop, petroleum will be pushed out to the wing side of the anticline. The process of such continuous migration is illustrated in Fig. 3.44. Petroleum, after being forced out into the bottom of the structure, migrates up-dip to be deposited in the next trap. Trap 1 in A in the continuous process shown in Fig. 3.45 corresponds to Stage 2 of Fig. 3.44. In C of Fig. 3.45, Trap 1 in the lowest down dip is filled with gas, Trap 2 in the next contains oil and gas, and Trap 3 contains only petroleum, but Trap 4 in the highest up-dip contains only water yet. Eventually, however, Trap 4 will be filled with petroleum spilled out from Traps 1, 2 and 3. The above is the gist of Gussow's theory of differential entrapment.

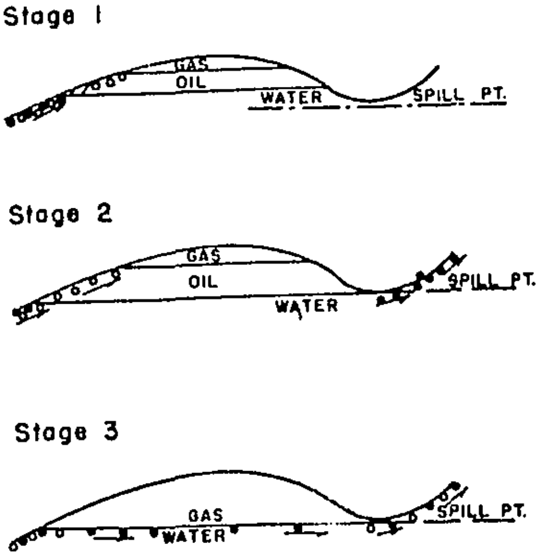
Fig. 3.43



The volume of a gas varies directly as the temperature and inversely as the pressure, a physical phenomenon known as the Law of Gasses. For our purpose we may disregard the effect of the temperature

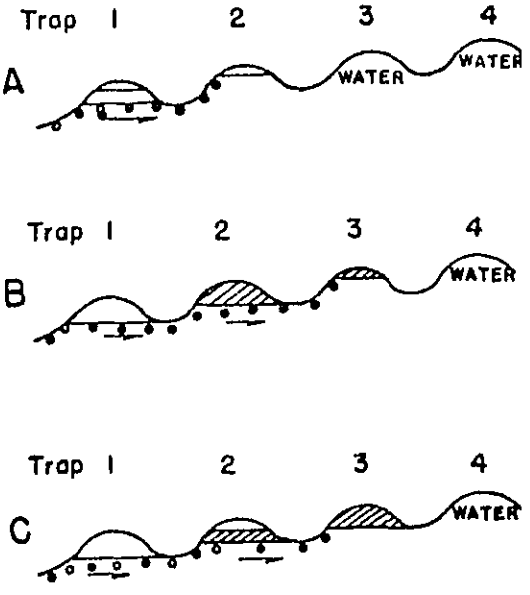
(Levorsen, 1967)

Fig. 3.44



The selective trapping of oil and gas. Stage 1: *The oil and gas are above the spill point, and both will continue to be trapped until the free water is all displaced and the oil-water contact reaches the spill point.* Stage 2: *Gas continues to be trapped while oil spills out and goes on up the dip.* Stage 3: *Gas has filled the trap and spills out up the dip. Oil bypasses the trap and goes on up the dip.* [*Redrawn from Gussow, Proc. Alberta Soc. Petrol. Geol., June 1953, p. 4.*]

Fig. 3.45



In the series of traps at A, trap 1 is in the state of Stage 2 (Fig. 12-18): oil is being spilled out into trap 2. Traps 3 and 4 are full of salt water. In B, trap 1 has spilled all its oil into trap 2. Trap 2 is full of oil, and the excess is passing up the dip into trap 3. Trap 1 is full of gas. In C, trap 1 is unchanged, trap 2 has a gas cap (the excess gas coming from trap 2), trap 3 is full of oil, and trap 4 is still full of water but will be the next to be filled with oil spilling out of trap 3. [Redrawn from Gussow, Proc. Alberta Soc. Petrol. Geol., June 1953, p. 4.]

Levorsen summarized the process of petroleum accumulation in traps in secondary migration as follows:

① There are some deposits formed in situ, there being no long-distance migration of petroleum. This is the case where reservoir rocks have been formed already as a trap in the diagenesis process of sedimentation.

② Where a trap was formed after diagenesis, presumably oil and gas, starting from a state of dispersion, migrated to the trap through reservoir rocks saturated with water.

③ Migration distance of oil and gas greatly varies, depending on the distance to the trap from the point where oil and gas entered the reservoir rocks.

④ Some petroleum might have been carried with water in such states as solution, colloidal dispersion, spots, or dispersed oil particles, but most of the migration – without having anything to do with water migration – would have depended on buoyancy connecting oil and gas in water.

⑤ To cause an upward migration of oil and gas before buoyancy acts, the oil and gas concentration (continuous phase) has to be high in gentle-slope strata, but may be low in steep-slope strata. Concentration of oil and gas necessary for migration takes place in various manners: (a) Local concentration may have occurred in reservoir rocks particularly where there were large pores facilitating the entry of oil and gas. (b) Colloidal hydrocarbon particles might have gathered in plume form along the surfaces of permeable strata. Gas dissolved in stratum water might have turned into gas bubbles on account of expansion and formed local concentrations. (c) Gas released so as to be deformed to the extent that globules of oil and gas, as a continuous phase, communicate through the barriers between pores, might have expanded. Such expansion of gas is brought about by decline of pressure owing to any of such causes as regional tilting and denudation, change of head of stratum water, dilatancy, faults or temperature change.

⑥ Once a mass of oil and gas has gained enough buoyancy to start moving by itself, it takes in dispersed oil and gas in the course of migration and grows further, the buoyancy being augmented. Augmentation of buoyancy accelerates the migration velocity, and such masses keep on migrating toward up-dip, namely low-pressure parts, until encountering a trap or other barrier, to form a deposit.

⑦ Migration of oil and gas occasioned by buoyancy can take place in the opposite direction from water migration in the reservoir rocks where a hydromechanical pressure gradient exists. The effect of water flow changes the position and inclination of oil-water contacts. An oil-water contact under hydrostatic conditions is horizontal, while one under hydrodynamic conditions inclines toward the water flow direction.

⑧ Some petroleum will be left in pores as dispersed particles. Its quantity is governed by many factors such as pore size (in particular, where porosity and permeability vary), water quality, gas-oil ratio, and hydrophylic characteristics of oil reservoir rocks.

⑨ The optimum conditions for migration would be probably found where the up-dip direction of reservoir rocks coincides with the direction of pressure release along the hydrodynamic pressure gradient.

(4) Disappearance of deposits

Disappearance of petroleum deposits means that petroleum in deposits scatters away or degenerates into substances unworthy of working. Roughly divided from the viewpoint of origin theory, there are two cases. One is the case occasioned by the loss of petroleum preservation conditions owing to the cycle of sedimentation and diastrophism. The other is the case of destruction of workable petroleum deposits by thermal metamorphism resulting from cumulative loads or igneous activities.

Regarding this problem, Mitsuchi (1963) summarizes various cases. These will be quoted here, with some supplementary comments:

ⓐ Disappearance of deposits owing to loss of petroleum preservation conditions

- i) Strata of rocks containing petroleum deposits are remarkably upheaved, and formations covering the deposits are denuded, resulting in scattering of petroleum. Heavy fractions remain near the surface or the seabed, and are subjected to a kind of water erosion; some turn asphaltic and are further denuded away.
- ii) New stress on the deposit-covering formation due to diastrophism causes fissures and fractures there, through which petroleum scatters away.
- iii) Traps where deposits exist lose their function as traps because of transformation of the strata holding them, resulting in migration of petroleum to other places or migration to the surface or the seabed ending up in scattering away.
- iv) Considerable transformation of topography owing to differential upheaval or subsidence of the ground causes a vast change in the distribution of underground water. On account of that, petroleum forming the deposit is rendered unable to remain in the existing trap, and migrates elsewhere or scatters away to the surface or the seabed.

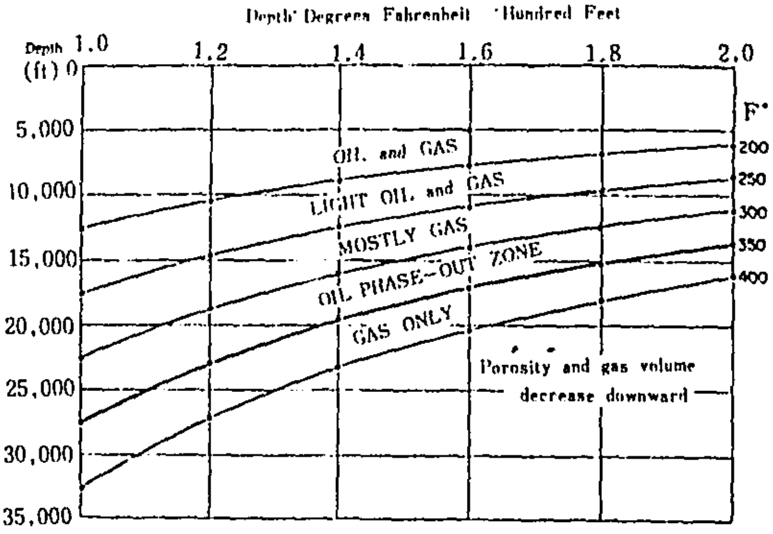
ⓑ Disappearance of deposits caused by thermal metamorphism of petroleum

- i) A petroleum deposit is involved in a new orogenic movement and accompanying igneous activities. Being exposed to high temperature, most of petroleum is gasified and converted to carbonaceous matter.

ii) The rise of geothermal temperature accompanying cumulative loads brings about thermal decomposition of petroleum, which results in petroleum being gasified and turned into fixed carbon–in extreme instances, being changed into methane and graphite–and, thus results in loss of a workable petroleum deposit.

Recently, in particular, importance has been attached to knowing the depth limits of occurrence of deposits worthy of working. This is related to the problems of estimating mineable reserves and of drilling cost. Degeneration of petroleum proceeds according to paleogeotemperature rather than to depth. Diagrams of Landes (1967) and Pusey (1973) are presented in Figs. 3.46 and 3.47.

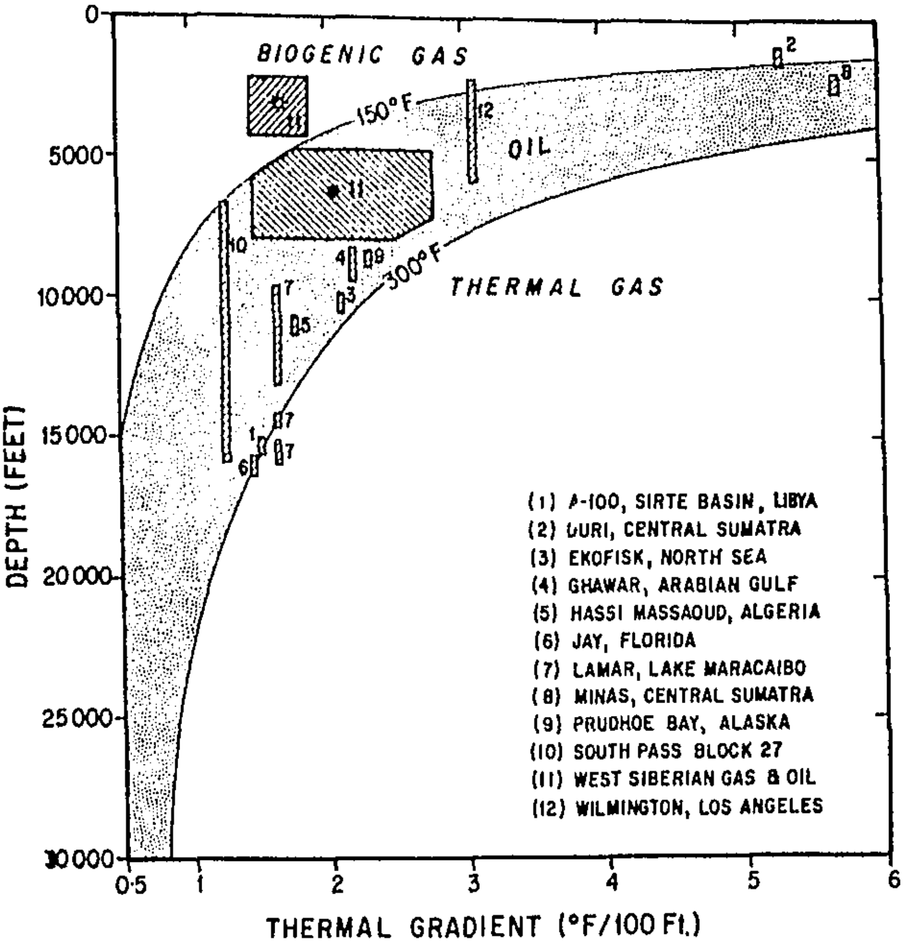
Fig. 3.46



Earth temperatures and occurrence of oil and gas. (Landes, 1967)

Fig. 3.47

(W. C. Pusey, 1973)



Liquid Window Concept. Giant fields of Mesozoic and younger age are found with geothermal gradients ranging from 1·0 to nearly 6·0°F per hundred feet. A "hot" gradient does not mean hot temperatures but indicates shallow production (e.g. Minas Field). The vertical bar indicates the span of significant production in each field. Oil shows and completions are known at temperatures greater than 300°F, but 99+ per cent of the world's oil is found at temperatures cooler than 300°F and most is found at temperatures of 250°F or less (Baybakov, 1969; Landes, 1964; Rogers et al., 1972). Many oil reservoirs are found at temperatures of less than 150°F, but invariably they are associated with either significant uplift after heating or, less commonly, long-distance migration updip. Huge gas reserves in the northern part of the west Siberian basin are biogenic. Carbon isotope data (Yermakov et al., 1970) clearly show that the gases are highly deficient in C^{13} and have formed at low temperatures. In the central and southern part of the basin, geothermal gradients are higher and oil is found at temperatures of 130 to 250°F (Dickey, 1972).

4.3 Purpose and Method of Oil Exploration (Excluding Geophysical Exploration and Well Exploration)

Geology is a natural science aimed at analyzing the state of the earth. At the same time it has the nature of historical science in which the growth and development of our planet is investigated. The scope of this science has now extended to boundary areas with physics, chemistry and biology, and the subjects dealt with are becoming increasingly diversified. Today, geology divides into various branches including historical geology, stratigraphy, petrology, mineralogy, mineral deposits, etc., each constituting an independent system of study and each based on faithful observations of field phenomena. Geological survey in the broad sense of the term refers to the gathering and analyzing of data from all these fields that are necessary in conducting geological study.

Geological surveys are not limited to scientific research. They are used directly and indirectly in various practical fields such as oil-mining, coal-mining, forestry, irrigation and riparian projects, civil engineering, agriculture and building construction. In oil mining, various geological survey methods are used in the first step, viz., in determining how to find a deposit, or in oil exploration. Some of the methods are listed in Table 4.1.

Table 4.1

Kind of survey	Description and purpose	Remarks
Surface geological survey	Field survey in which outcrops are directly observed to determine geology, structure, etc.; geological maps and sectional maps are drawn.	Conducted in mountains and other places where outcrops are found.
Geological survey by aerial photography	Aerial photographs are interpreted for geological determination of topography; strata distribution and structural growth are grasped.	Useful in areas with poor outcrops and difficult access.
Survey of extinct animals and plants	Sampled fossils are assayed to determine stratigraphic horizons and geological ages involved.	Chiefly involves indoor work.
Geochemical survey	Soil, rock, water and gas samples are chemically analyzed, and specified components are detected, to investigate the possible presence of deposits.	
Petrological survey	Physical properties and mineral composition of rocks are investigated, to observe the formation of rock and strata as well as sedimentary environments and degeneration.	
Sedimentological survey	Minute phenomena in sedimentary rocks are observed; on that basis, strata formation, geological structure, and tectonic movement are studied.	Chiefly field survey; electrical logging of well is used occasionally.
Underground (well) geological survey	Underground geology is continuously investigated by drilling, to clarify stratigraphical features, structure, and the presence or absence of deposits.	Direct survey, but involves high costs.

In addition, there is geophysical exploration, which falls under the category of geological survey in the broad sense of the term. Here, geophysical exploration will be treated in a separate section.

4.3.1.2. Geological Survey by Aerial Photography

(1) Aerial Photography and Photogeology

Aerial photography was first attempted in the second half of the 19th century. And in the early 20th century it already reached a practical stage owing to spectacular advances in photographic materials and optical instruments. Development of aerial photography was given added momentum during World War II, when it was used for military purposes with astonishing results. With the resulting fast progress, aerial photography has now come under the limelight as a powerful tool in the present age of information science and technology.

Today, aerial photography is employed extensively in the planning and surveying for civil engineering projects including roads, railways, dams and rivers as well as in topographical and geographical surveys such as for forest and soil distribution. Moreover, aerial photography has become an indispensable means of drawing up high-precesion topographical maps required for such surveys. It is also instrumental in archeological discoveries (ancient tombs, etc.) and in investigating disaster-hit areas and determining the course of tides and floods. Thus, aerial photography is helpful in all phases of human activities from cultural pursuits to welfare.

This wide application is made possible by the fact that aerial photographs are taken in such a way that objects on the ground can be viewed three-dimensionally from the air, thus providing the advantage that details of land objects can be observed as they are over a wide area. Among the applications of aerial photography that take full advantage of this feature is the application to geology.

That aerial photography came to be used on a full scale as a means of geological survey was in 1955, when Ray defined the term "photogeology" as a science of studying and interpreting aerial photographs for the purpose of gathering geological information, and also as including the mapping of data obtained from the photographs. The large-scale photogeological survey conducted by the U.S.A. over a period of seven years starting 1947 in the North Slope oil fields of Alaska facing the Arctic Ocean produced remarkable results. Since then, aerial photography in this field has made rapid progress.

(2) Types of Aerial Photographs

Aerial photographs are divided into vertical and side photographs. Classified by photosensitive materials, they are grouped into monochrome (panchromatic), color, infrared photographs, etc. Color photographs are highly useful in reading strata and faults because color survey is emphasized. In infrared photographs, rivers show in black, while, due to chlorophylic effect, broadleaf trees appear light and needle-leaf trees dark, so that they are helpfull in surveying marshland and dry land and also in jungles where the vegetation reflects the lithology beneath. In geological surveys, however, vertical black-and-white photographs are preferred because panchromatic film is cheaper than infrared film and provides as much information in geological interpretation.

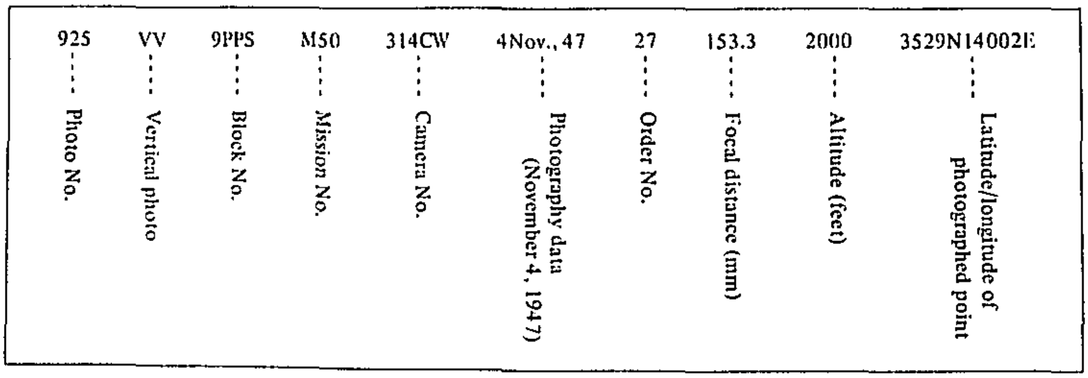
Among other types there are photographs used for special purposes, such as the thermic ray photograph which reflects the state of heat generation in the subject, the radar photograph which reflects chemical compositions, and the orthographic photograph in which all parts are reduced on the same scale and which are often used in topographic maps for military purposes. More recently, space photographs taken from artificial satellites have come into use. In the case of vertical three-dimensional photographs, for the convenience of observation, the size is limited within a certain range irrespective of the type of photograph. The standard size is determined by the camera angle, viz. the vertical angle of the cone of rays transmitted through the lens (Table 4.7). For photogeological use, wide angle photographs of 23cm square are most commonly used.

Table 4.7 Aerial Photographs

	Camera angle	Principal distance (focal distance)	Photograph size	Name of lens
Ordinary	60°	17 cm	14 cm x 14 cm	
		21 cm	18 cm x 18 cm	Aviotor (Wild)
Wide	95°	10 cm	14 cm x 14 cm	Pleogon (Zwiss)
		11.5 cm	18 cm x 18 cm	Metrogon (Zwiss)
		6" (15.2 cm)	23 cm x 23 cm	Aviotor (Wild)
Extrawide	100° ~ 120°	8.8 cm	23 cm x 23 cm	Super-Aviogor
		7 cm	18 cm x 18 cm	
		3.6 cm		U.S.S.R.

Aerial photographs are taken automatically and continuously by means of a camera built into the bottom of an airplane. As each photograph is taken, automatic recordings are made of the time, place and method of photography. This information is noted on the upper left corner of each photograph, as shown in Fig. 4.13.

Fig. 4.13 Notations on Aerial Photograph
(U.S. Military)



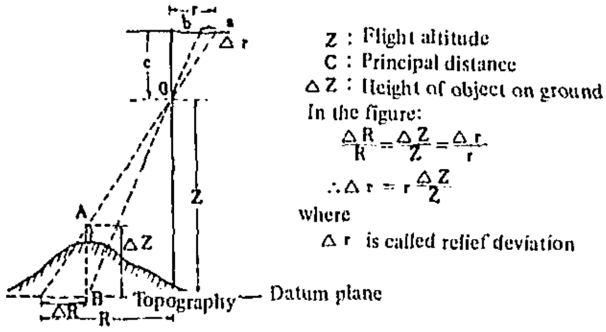
(3) Characteristics of Aerial Photographs

The greatest advantage of aerial photographs is that they make three-dimensional observation possible. This is due to the following characteristics.

1 Central projection is used.

A three-dimensional object can be projected on a plane by parallel, orthographic or central projection. The last-named method is used in aerial photography. In this method, an object with a height is projected on the photograph as two points. Deviation between the two points indicates the height. Under specific conditions, therefore, a three-dimensional presentation is obtained. This horizontal deviation in photographs of an object with a height is called relief deviation (Fig. 4.14).

Fig. 4.14



Z : Flight altitude
C : Principal distance
ΔZ : Height of object on ground
In the figure:

$$\frac{\Delta R}{R}=\frac{\Delta Z}{Z}=\frac{\Delta r}{r}$$

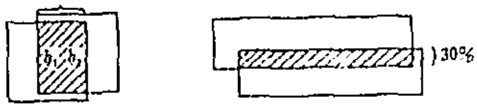
$$\therefore \Delta r = r\frac{\Delta Z}{Z}$$

where
Δr is called relief deviation

2 There are overlaps.

Each aerial photograph gives only a plane view. But simultaneous observation of two or more successive photographs will provide a three-dimensional view. In other words, three-dimensional observation always requires a pair of (two) successive photographs and, of course, the object for observation must appear in both photographs. Only the overlapping parts can be observed three-dimensionally. There are vertical and horizontal overlaps. The standard is 60% for the former and 30% for the latter (Fig. 4.15).

Fig. 4.15



Horizontal overlap Vertical overlap

▨ Hatched portions are overlaps.
h_1 and h_2 are highlights, both of which must be contained in the overlap. も両方の

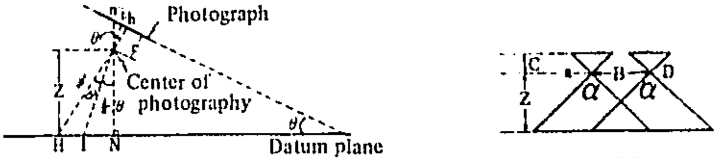
3 There is vertical exaggeration.

The phenomenon in which the apparent height on a photograph is unproportionally greater than what the actual height should appear is called vertical exaggeration. This phenomenon is present in varied degrees in any photograph. Even a small degree of exaggeration permits three-dimensional observation, but the greater the degree, the more convenient ingeological interpretation. While vertical exaggeration does not interfere with interpretation, it is important that the viewer should not be misled by it.

Another point that should be noted in dealing with aerial photographs is the fact that there are differences in scale even in one photograph, to say nothing of two successive photographs. This is because the lens cannot always be maintained at a horizontal position relative to the ground, so that a slight incline cannot be avoided in a vertical photograph. The deviation thus caused is called deviation of dip. When the dip deviation of the lens is within 4°, the photograph taken is treated as a vertical photograph. This degree of deviation does not obstruct three-dimensional observation. When the difference in scale between a pair of successive photographs is 15% or over, a three-dimensional view cannot be obtained.

Terms commonly used in aerial photography are presented in Fig. 4.16.

Fig. 4.16

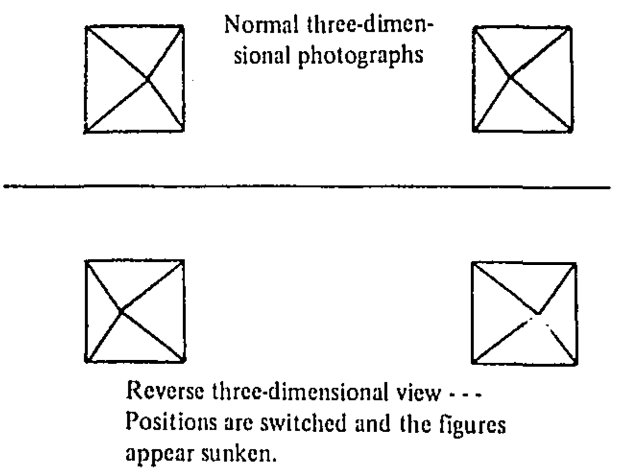


h(H) : Principal point
n (N) : Naider point
i (I)= Iso center
α : Camera angle
θ : Inclination angle of photograph

Z : Flight altitude
B : Base length of photography
C : Principal distance
$\frac{B}{Z}$ – Base-height ratio
$\frac{C}{Z}$ = Scale of photograph

(4) Three-Dimensional Observation and Instruments

Fig. 4.17 Visual Three-Dimensional Model



Normal three-dimensional photographs

Reverse three-dimensional view - - - Positions are switched and the figures appear sunken.

A close look at Fig. 4.17 will show the figures as pyramids. This is an example of a three-dimensional view. Aerial photographs are always observed in this state. Since observation by the naked eye will result in blurred figures and eye fatigue, an instrument such as shown in the photo is usually empoyed. This instrument is known as a mirror-type stereoscope. By placing under it two successive aerial photographs at a certain distance (usually 6 to 9 cm) apart, and observing from the top, a three-dimensional image is obtained. The lens has a focal distance of about 30 cm and a magnification of only 0.8, but the image can be enlarged by using a pair of binoculars (magnification: 4 to 8) although this will narrow the field of vision.

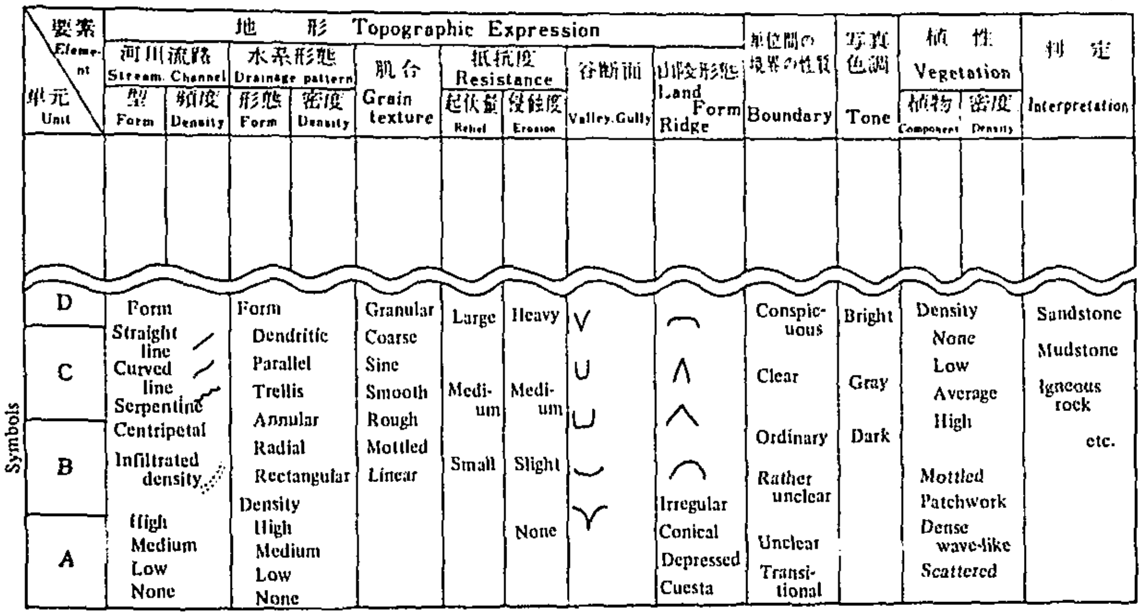
There are other similar instruments for observation, such as the pocket stereoscope (magnification: 2.5) and the prism type stereoscope (magnification: about 4).

(5) Analytical Elements in Photogeological Interpretation

Photogeological interpretation is usually made indoors, in contrast to surface surveys of outcrops which are carried out in the field. To obtain a higher accuracy, it is desirable that photogeological interpretation should be combined with a field survey. The procedure of photogeological investigation is: Preparation (preparation of original map; position finding) Interpretation (determination of geology and structure) Measurement (of dip,etc .) Overall charting (drawing of geological map). Interpretation forms the nucleus of this procedure.

Interpretation of aerial photographs with regard to stratification and structure requires the elements listed in Fig. 4.18. These analytical elements are appropriately combined to make an interpretation. Depending on the area photographed, some of the elements are useless. In arid areas, for instance, importance should be attached to the form of ridges and grain textures rather than to water systems. In lands like Japan, drainage systems and vegetation assume importance.

Fig. 4.18 Analytical Elements and Interpretation of Aerial Photographs

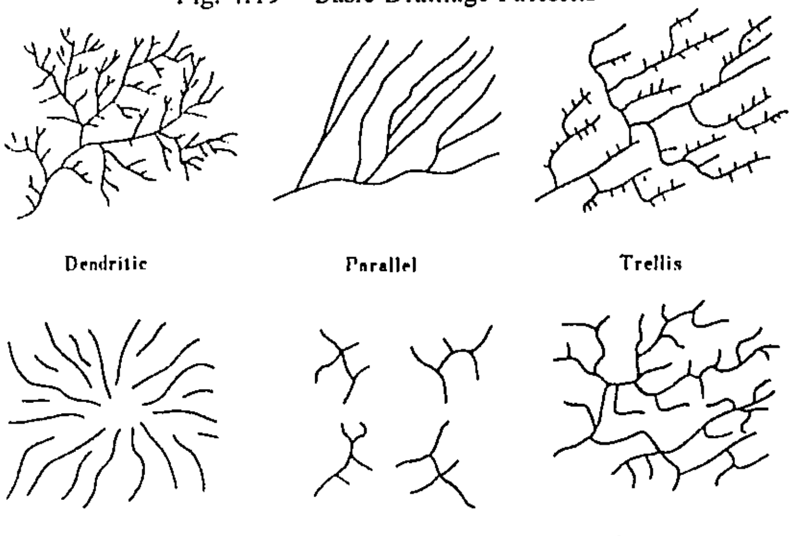


要素 Element / 単元 Unit	地形 Topographic Expression: 河川流路 Stream Channel: 型 Form	頻度 Density	水系形態 Drainage pattern: 形態 Form	密度 Density	肌合 Grain texture	抵抗度 Resistance: 起伏量 Relief	侵蝕度 Erosion	谷断面 Valley, Gully	山稜形態 Land Form Ridge	単位間の境界の性質 Boundary	写真色調 Tone	植性 Vegetation: 植物 Component	密度 Density	判定 Interpretation
Symbols D C B A	Form Straight line Curved line Serpentine Centripetal Infiltrated density High Medium Low None		Form Dendritic Parallel Trellis Annular Radial Rectangular Density High Medium Low None		Granular Coarse Sine Smooth Rough Mottled Linear	Large Medium Small	Heavy Medium Slight None	V U ⊔ ◡ Y	⌒ ∧ ∧ ⌒ Irregular Conical Depressed Cuesta	Conspicuous Clear Ordinary Rather unclear Unclear Transitional	Bright Gray Dark	Density None Low Average High *Mottled* Patchwork Dense wave-like *Scattered*		Sandstone Mudstone Igneous rock etc.

1 Drainage systems

Apart from individual rivers and streams, attention should be paid to drainage patterns and to their local anomalies and densities. Fig. 4.19 shows a few typical drainage patterns. Their geological characteristics are summarized in Table 4.8.

Fig. 4.19 Basic Drainage Patterns



Dendritic Parallel Trellis

Radial Annular Rectangular

Table 4.8 Characteristics of Basic Drainage Patterns

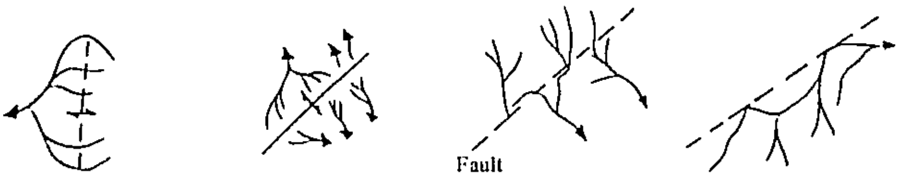
Basic pattern	Where found	Typical examples	Remarks
Dendritic	(1) Horizontal sedimentary facies (2) Homogeneous petrographic provinces (3) Crystalline petrographic provinces (4) Small petrographic provinces with uniform resistance	Black shale formations, gray shale formations, granite	*Consists of insequent streams
Parallel	(1) Inclined beds (2) Homogeneous petrographic provinces where dissection has just started (3) Petrographic provinces liable to form parallel fissures.	Well stratified sandstone formations, tuff formations	Stream path is oriented by parallel fissures.
Trellis	(1) Where hard and soft strata alter (2) Inclined beds and fold zones (3) Where strike fault is developed	Alternating strata of sandstone and mudstone	Has a nature intermediate between dendritic and parallel drainage system
Radial	(1) Areas with almost circular topographic elevation (chiefly reflecting geological structure)	Centrifugal type . . . Volcanic dome, dome structure Centripetal type . . . Syncline structure	
Annular	(1) Areas where two or more rocks with resistance difference are distributed circularly.	Dome structure forming alternating hard and soft strata	Subsequent stream* flows where resistance is low in rocks, and joins radial consequent stream*
Rectangular	(1) Areas where homogeneous crystalline rocks are distributed. (2) Areas where faults and joints cross.	Where there is violent blocking, and areas of igneous rocks.	

*Insequent stream	Develops irrespective of initial topography or geological structure
Subsequent stream	Flows where resistance is lowest.
Consequent stream	Governed by initial topography, flows from high to low points deep underground.

A close investigation of horizontal patterns will occasionally reveal a heterogenous pattern sharply contrasing the surrounding pattern. This is known as a drainage anomaly and is helpful in structural interpretation (estimation of anticlines and faults). Some examples are shown in Fig. 4.20.

Fig. 4.20 Some Drainage System Anomalies

(a) Arc (b) Change of meander course (c) Compound (d) Radial



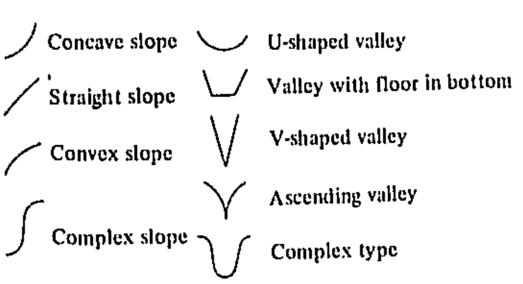
(e) Bend (f) Diversion by Anticline (g) Drainage dislocated by Fault (h) Drainage controlled by Fault

Meanwhile, the density of a drainage pattern is highly useful in determining lighofacies. A difference in density means a difference in volume between surface water and ground water. And this difference reflects the infiltration capacity of rocks. Generally speaking, in areas where high-infiltration porous rocks such as sandstone and conglomerate are prevalent, the drainage system is coarse, and in areas of mudstone it is fine.

2 Valleys, gullies and ridges

The form of a valley or gully is governed by the resistance of rock to erosion by streams, and that of ridges by the resistance to weathering. Fig. 4.21 shows some forms of slopes and valleys. Generally, nonconcentric high-porosity materials (sand, gravel) tend to form V-shaped valleys with a sharp precipice at the upper end of the slope, while mudstone is likely to form U-shaped valleys.

Fig. 4.21 Forms of Slopes and Their Sections



3 Grain texture and color

Grain texture and color are analytical elements that are peculiar to aerial photography; hence they have a disadvantage in that they are dependent on the condition of the photograph involved and on the subjective impression of the viewer. Specifically, grain texture gives a different impression depending on the scale of the photograph, and color depending on the position of the subject relative to the sun, as well as on the sensitivity of the film and on the filter used. On the other hand, they offer an advantage in that they faithfully reflect the nature of rock and strata as long as the conditions are identical.

Grain texture is an element that is related to the grain size and homogeneity of rock, so that it provides a key to discerning the difference in lighofacies. Table 4.9 shows a model of relationships between grain texture and lighofacies.

Color is a reflection of rock color and also of the density of vegetation. In either case, it represents the nature of rock. In artificially planted areas, however, color has a low reliability as an analytical element.

4 Role of climatic geography

The climatic geographical element does not manifest itself directly in a photograph. Some rocks, however, are severely affected by rain, temperature and humidity and, depending on the area, undergo a marked change in appearance. Cases in point are limestone and granite. As will be seen from Table 4.10, they present diametrically opposite topography depending on whether they are found in wet temperate areas or in arid tropical areas.

Table 4.10

		Limestone	Granite
Areas of temperate and humid climates	Temperate climate	Vulnerable to physical weathering, hence depressions are formed (conical in humid tropical areas). Karst topography, limestone caverns.	Has great resistance to erosion and forms elevations; there is great relief.
	Humid climate		There is violent chemical weathering; in elevated old-aged topography resistant to erosion, honeycomb textures are seen.
Areas of cold climate		Karst topography is not prominent because ground water is frozen for some time of the year.	Topography is marked by heavy rises and falls (acicular texture).
Areas of high-temperature and dry climates	Temperate and semi-dry climates	There is vey little CO_2 because of high temperature, although precipitation is limited; hence no karst topography is seen.	Weak rocks resulting from strong influence of physical weathering; biotite granite, in particular, forms depressions.
	Dry climate	Rainy season is short and there is great resistance to chemical weathering, so that topography is marked by protuberances.	

(6) Determination of lighofacies

With aerial photos, one can easily distinguish alluvium from lower formations like the Tertiary one, and determine the distribution in alluvial fans and sand, as well as the status of volcanoes. Generally, however, determination of lithofacies is one of the most difficult tasks in a photogeological survey. Different analytical elements are combined to make an interpretation, but this is extremely difficult in areas where vegetation is highly developed, topography is complicated, and strata distribution is complex. Differentiation of sedimentary rock is almost impossible without considerable experience. Table 4.11 shows a guide to interpretation for a typical Tertiary formation in Japan, but this should not be taken as a golden rule.

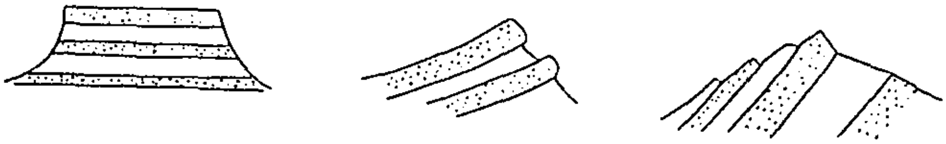
On the other hand, differentiation between igneous and sedimentary rocks is relatively easy. The former is found in higher elevations and rugged terrains, and does not present lineation or cuesta patterns (to be discussed later in this text) of bedding.

(7) Determination of Structure

From aerial topography, one can determine the strike and dip by the following methods:

1 Find a special topogrpahy as in Fig. 4.22

Fig. 4.22 Special Topographical Features Helpful in Determining Dips



Mesa
Horizontal

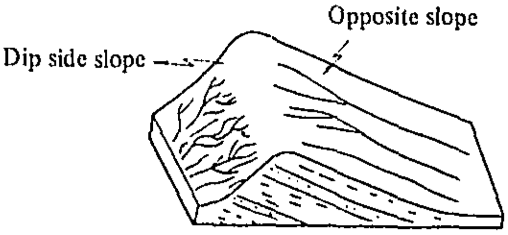
Cuesta
Gentle slope (within 10°)

Fog-back
Steep slope

Such topography is likely to form in well stratified beds and alternating hard and soft strata.

2 Compare the density and length of drainage systems on slopes (Fig. 4.23). When the dip is below 45°, the stratum is inclined toward the dip side slope.

Fig. 4.23 Difference in Drainage Systems Reflecting Dips



3 Find the key bed and track it down, as in the case of surface surveys. In photogeological surveys, anything conspicuous will serve as a key bed.

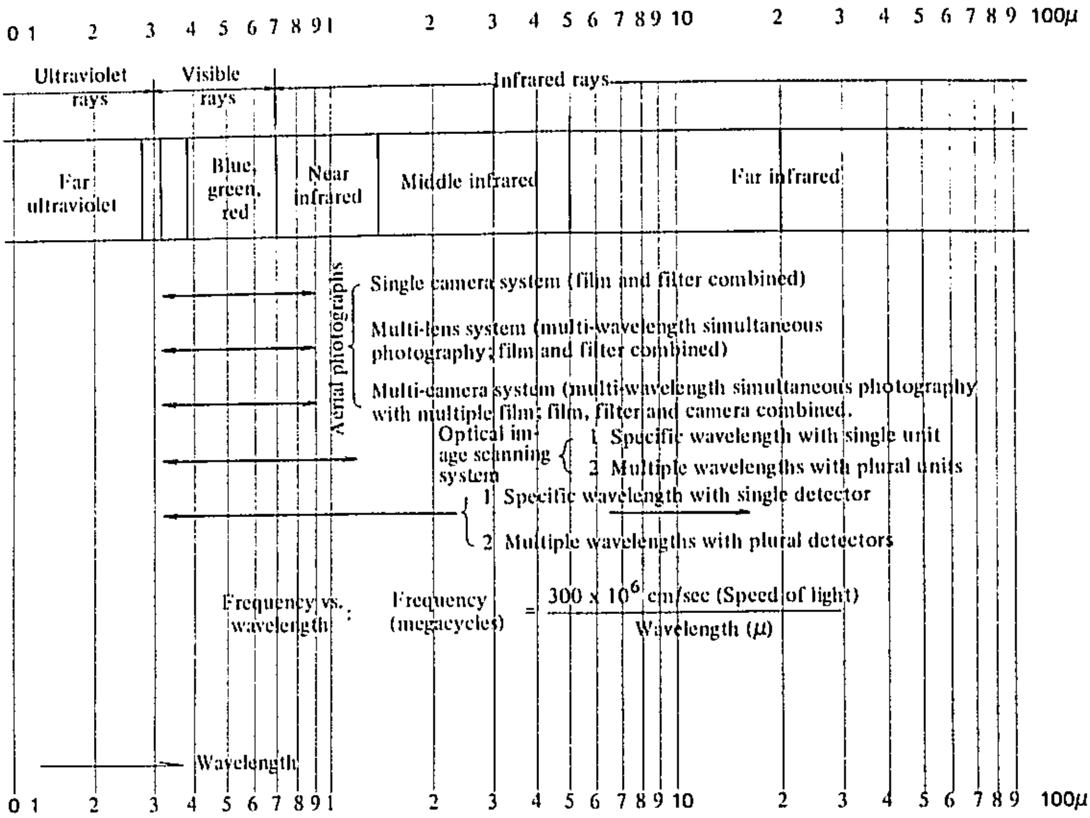
4 Investigate the pattern of lineation and take its longitudinal direction as the dip.

Folds and faults can be found with considerable accuracy by combining the strike and dip thus found with drainage anomalies.

(8) Preparation of Photographs and Geological Maps (Comprehensive Mapping)

Whereas in a surface survey, a geological map can be prepared manually because the survey is conducted on the basis of a topographical map, in a photogeological survey, a stereoplotter is necessary because information must be transferred from photograph to topographical map. In preparing a photogeological map, a sketch master such as shown in Photo 4.1 is usually employed. This equipment is easy to operate and permits compensation for deviations due to inclination of photographs and for differences in scale. Moreover, it is available at low cost (about ¥ 300,000). Among other apparatus, there are such third grade order plotters

Photo 4.1



Electromagnetic wavelength regions and remote detecting systems (limited to the range from 0.1μ to 100μ.

such as radial line plotter, stereo top and stereo micrometer. Unlike the sketch master, these permit plotting while making three-dimensional observation, and require specialized knowledge.

A photogeological map thus made is basically the same as a surface geological map. By adding to it data checked on the field, an accurate geological map can be drawn up in a short time.

From aerial photographs, one can directly measure dips and also prepare sectional diagrams, but these operations are too specialized to be described here.

(9) Side Looking Airborne Radar (SLAR) - - - A New Exploration Method

The term "remote sensing" in its broad sense includes various methods of airborne geophysical prospecting. Here, however, it will be defined as a means of sensing and evaluating the radiated and reflected energy of electromagnetic waves from objects. Two categories of methods are available: sensing energy radiated from an object, and sensing energy reflected from an object to which artificial energy has been transmitted. In the former category, there are measurement of infrared radiation temperature and video reception of infrared radiation temperature. In the latter, there is the side looking airborne radar (SLAR)method in which microwave or radar wave is transmitted and the intensity of reflected energy is displayed in the form of image. One of the first perfected methods is aerial photography.

Recently, there have been developed various non-photographic remote sensing devices which are effective over a wide range of wavelengths from the ultraviolet to microwave region. SLAR, which is now attracting attention, will be described in some detail.

SLAR is an airborne device that transmits, on one or both sides of the aircraft, microwave pulses in a direction perpendicular to the flight line and receives and records the reflected pulses. It alternately repeats transmission and reception via an antenna installed on the aircraft. The transmitted microwave reaches the ground whence it is bounced back. Reflections from different parts of the ground are received with time lags and at different intensities. In other words, on the basis of time-amplitude correlationship, the microwave received is converted to a video signal. The signal undergoes brightness-modulation and is then recorded on film. As transmission and reception are repeated, the ground surface is scannned at the beam width, until the entire field of vision is covered. By winding the exposed film at a speed proportional to the flight velocity, recordings of the area of survey are obtained continuously on a strip of film. Radars used most extensively today operate in the wavelength range of from 0.86 cm to 3.3 cm.

The first and foremost advantage of this method is that it can be used any time of the day under almost any weather condition. Another is that it can cover a wide area in a short time. While it cannot be applied to areas directly under the flight line, it can cover those on both sides at a width ranging from 1 to 60 km. In geological surveys, this method can be used effectively for mapping geological structures. Since the shades of ground objects can be stressed by varying the direction and altitude of flight, the geological structure dominating the topography can be emphasized and grasped clearly by selecting a flight course parallel to the general direction of the dominant geological structure. Microwave penetrates the covering of vegetation, so that information on geological structure stripped of vegetation can be had. In this respect, this method is ideal for extensive preliminary surveys in hot and humid jungle areas covereduunder thick vegetation. (Geological News, December 1972, pp. 44–59)

4.3.1.3 Paleobiogeographical Survey

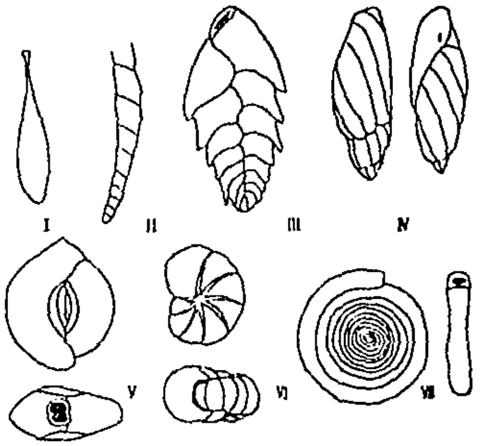
In oil geology, fossils (fossil organisms) to which special importance is attached are small fossils including those of foraminifera, pollen, spores, diatoms, and nannoplankton. Large fossils (bivalves, ammonites) do not hold a significant place here because they cannot be identified from well data. Small fossils regarded with particular importance are those of planktonic foraminifera, which permit stratigraphic correlation on a worldwide basis. In recent years, stratigraphic horizons for oil and natural gas prospecting have come to include non-marine formations in addition to marine formations. Hence, in strata where foraminifera are absent, use of diatoms, pollen, etc. is being attempted. As a means of research in petroleum geological survey, foraminifera will be discussed.

(1) Classification of Foraminifera

Biologically speaking, foraminifera are one-celled organisms belonging to the order Foraminifera among Pseudopoda, Protozoa. They are divided broadly into large and small foraminifera, the former having a complex internal structure and the latter a simple one. Among the large foraminifera (higher foraminifera), there are the fusulina of the Paleozoic era and the nummulites of the Cretaceous period of the Mesozoic era. These are standard fossils used in time correlation of strata. Generally the habitat of large foraminifera is limited to clear shallow sea bottoms in the tropical and subtropical zones, with the result that the stratigraphic horizons and areas for oil prospecting are also extremely limited.

On the other hand, small foraminifera are divided into benthic and planktonic types. Benthic foraminifera, distributed from the frigid polar regions to the tropic zone, are found in brackish waters as well as in seas ranging in depth from 4 to 5,000 meters. They are particularly numerous in waters shallower than 1,000 meters. Their fossils are contained abundantly in marine formations throughout the world and, consequently, their range of distribution is far more extensive than the large foraminifera. The planktonic foraminifera are widely distributed in surface waters of both cold and warm currents so that their fossils are contained in huge quantities in marine formations. In the field of oil geology and oil mining, therefore, mention of microfossils and micropaleontology immediately brings to mind fossils of foraminifera of both the benthic and planktonic types. A brief discussion will be made of small foraminifera. Typical forms of foraminifera are illustrated in Fig. 4.24.

Fig. 4.24 Various Arrangements of Loculus



I	Single loculus.
II	In a row along a straight or slightly curved line.
III	In two rows along a straight line
IV	Wound spirally.
V	Developed alternately around an axis at 180° or smaller angles.
VI	In a vortex.
VII	Annular or in concentric circles.

(2) From Sampling to Identification

Foraminifera fossils are gathered from surface strata and from well cores and cuttings. Samples are sought in mudstone and sandstone at depth intervals of 5 to 20 meters. About 100 to 200 g of them are taken and treated by roller mill and with chemicals, then washed with water, dried, and observed under microscope. The foraminifera thus collected are divided largely into benthic and planktonic types, then sorted into biological classifications and individuals of the same genera are counted. The results are entered in a species chart as in Table 4.12, which shows the distribution by specified species. Fig. 4.25 shows fossils of some of the benthic foraminifera found numerously in northeastern Japan along the Japan Sea. In surveys of both surface and well geology, the most basic matter related to oil geology is to differentiate strata as finely as possible and accurately correlate their data with surface and we well data at other places. Classification of lithofacies is made visually, or by electric logging, or by variation of fossils, but these classifications do not necessarily agree with each other.

Classification of strata by fossils is designed to determine the vertical distribution of fossils and fossil groups. Each section thus classified is called a fossil zone.

Fossil zones based on small foraminifera are classified with the characteristics of biographical divisions as a guide. Fig. 4.26 shows a model.

Table 4.12 Part of a Species Chart

Basic drilling
(off Sawame)

Sea surface at Minezawa-mura,
Yamamoto-gun, Akita Prefecture

Drilling started: June 27, 1968
Drilling discontinued:July 24, 1968
Mine abandoned: August 5, 1968
Depth drilled: 2,504.50 m

Note: Total foraminifera fossils in 100 g core

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REPORT No. SHEET. No.

EXAM. BY K. Takahashi
REPORT DATE

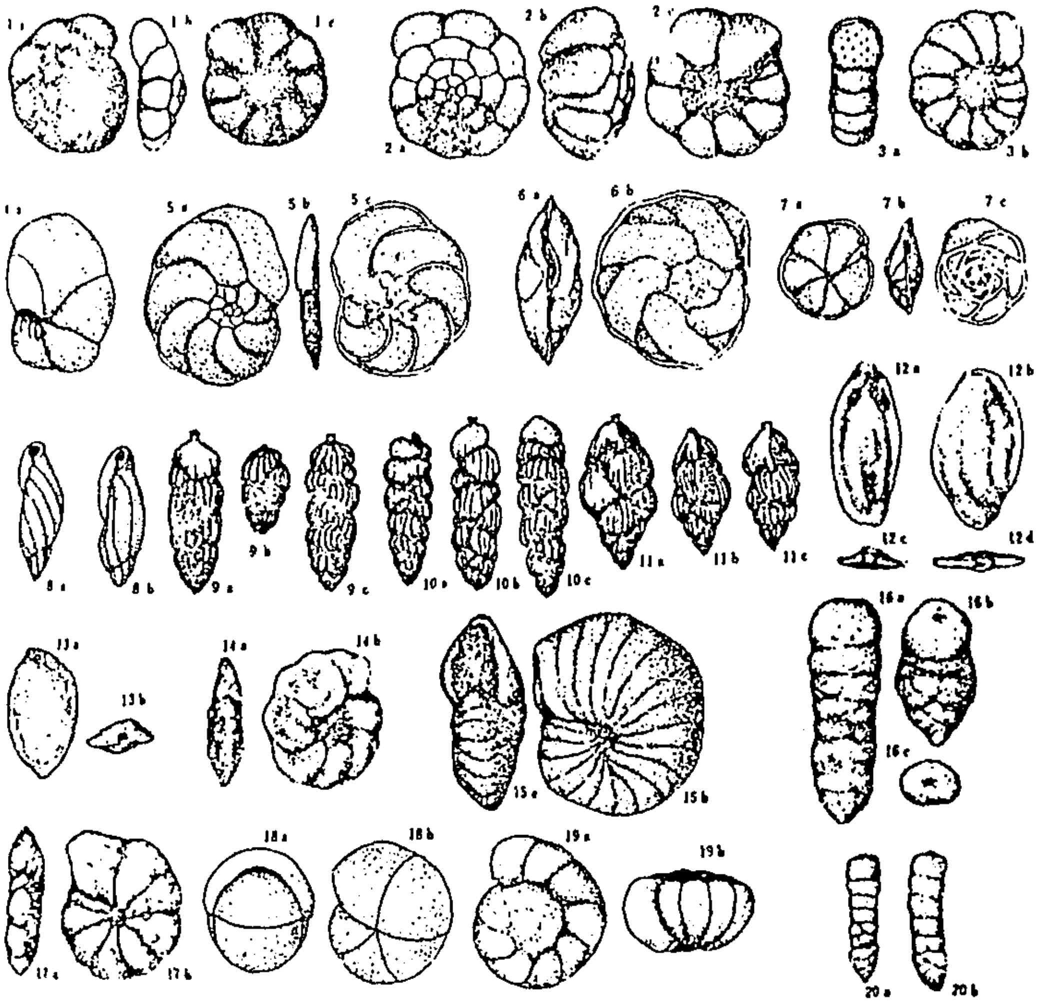
Stratigraphic *horizon*: Sasaoka formation; Upper Tentokuji formation

Fossil zone: N. F.; Cribrononion Subgranulosum; Uvigerina akitaensis - Islandiella cf. margareta

Kind of fossil \ Sample depth	NF 210m	NF 280	NF 310	NF 340	NF 370	NF 400	NF 410	NF 420	430	440	450	460	470	480	490	500	510	520	530	540	550	560
Globigerina bulloides															65	15	35	35	90	575	10	12
Globigerina pachyderma									1			1	1	1	70	15	5	11	20	130	12	700
(3) Globigerina spp.											1			9								
(4) Globigerina foliata												2	8	7	145	35	61	63	72	170	142	400
(5) Globigerina sp.																						
(6) Globorotalia inflata																						
(7) Globorotalia cf. inflata																						
(8) Globorotalia aff. acostaensis																						
(9) Globoquadrina dutertrei																						
(10) Orbulina universa																						
(11) Ammonia takanabensis											14	1	1	1								
(12) Ammonia japonica									5		9	1	1	2	1							
(13) Pseudorotalia gaimardii									3	21	26	12	20	1								
(14) Cribrononion subgranulosum									6	3	21	76	28	105	41	18	2	1	2	5		
(15) Buccella frigida									7		22	154	97	176	50	85	32			5	2	
(16) Florilus manpukuziensis									5	2	8	16	8	11								
(17) Brizalina robusta											5	18	7	25	8							
(18) Bulimina marginata									1		9	15	3	11	4	5	17	1				
(19) Quinqueloculina sp												1	1	3	2							4
(20) Guttulina yabei											10	20	19	4	1	2		1		25		
(21) Epistominella pulchella											1	4	2				1	13	90	210	182	204
(22) Buccella frigida carida												1	2	6								
(23) Cribrononion clavatum												30	49	80	122	370	168	11	50	55	14	112
(24) Cibicides lobatulus													1	3	2							
(25) Islandiella cf. margareta													1		10	10	1	14	30	160	146	388
(26) Cassidulina norcrossi															29	61	26	14	20	55		44
(27) Globocassidulina subglobosa															2		2	2	2	10	60	120
(28) Uvigerina akitaensis															9	6	4		30	35	16	
(29) Trifarina kokozuraensis															28	3	6	51	200	165	12	56
(30) Uvigerina sp.															3		5	1	10			

Kind of fossil \ Sample depth	570	580	590	600	610	620	630	640	650	660	670	680	690	700	710	720	730	740	750	760	770	780
Globigerina bulloides	2	1	12	12	6	16	55	625		105	90	50	110	30		50	51	50	26	2	87	7
Globigerina pachyderma	400	100		20	210	200		175	25	15	10	55	15	15		10	40	11	27	1	27	
(3) Globigerina spp.																			5		21	
(4) Globigerina foliata	400	40				200		375	25	60	30	100	15	15		27	65	15	26	3	45	1
(5) Globigerina sp.																						
(6) Globorotalia inflata																						
(7) Globorotalia cf. inflata																						
(8) Globorotalia aff. acostaensis																						
(9) Globoquadrina dutertrei																						
(10) Orbulina universa																						
(11) Ammonia takanabensis																						
(12) Ammonia japonica																						
(13) Pseudorotalia gaimardii																						
(14) Cribrononion subgranulosum							2						1	1								
(15) Buccella frigida					10	10			5	5												
(16) Florilus manpukuziensis																						
(17) Brizalina robusta									2		1		3	1								
(18) Bulimina marginata					2				5		1											
(19) Quinqueloculina sp							2	1														
(20) Guttulina yabei																						
(21) Epistominella pulchella	904	180	160	98	236	112	180	15	30	75	80	72	37	21		3	8	22	24	5	56	10
(22) Buccella frigida carida																						
(23) Cribrononion clavatum	260	32	60	6	36	50	60	5	30	45	40	25	24			3		6	7		12	
(24) Cibicides lobatulus																						
(25) Islandiella cf. margareta	1000	140		200	144	242	120	6		10	7	5	2			2	42	17	16	1	36	
(26) Cassidulina norcrossi	40	80	10	26		20	4	1		15	10	6	1				6	5	5		13	2
(27) Globocassidulina subglobosa	380	40	10	15	124	60	50	2	15	5			1	9			6		10		5	
(28) Uvigerina akitaensis	12	22	4	10	34	66	25	9		65	10	20	29	63		36	11	21	58	8	122	12
(29) Trifarina kokozuraensis	200	10	8	2	28	54	12		10	30	20	40	12	16		3	9		2			
(30) Uvigerina sp.							2	6										1				

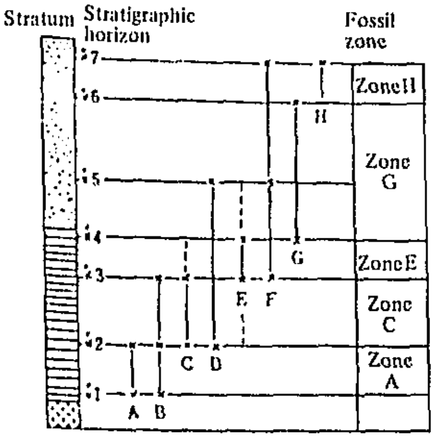
Fig. 4.25 Major Benthic Foraminifera Fossils in Tertiary System on Japan Sea Coast of Northeastern Japan (From Asano)



1 a, b, c	Ammonia of beccarii (Linnaeus) × 26
2 a, b, c	Ammonia japonica (Hada) × 20
3 a, b	Cribroelphidium yabei Asano × 20
4	Baggina totomiensis Makiyama × 29
5 a, b, c	Hanzawaia nipponica Asano × 41
6 a, b	Cassidulina yabei Asano × 26
7 a, b, c	Epistominella pulchella Husezima & Maruhashi × 48
8 a, b	Buliminella elegantissima tenuis Cushman & Mcculloch × 41
9 a, b	Uvigerina akitaensis Asano × 42
10 a, b, c	Uvigerina yabei Asano & Nakamura × 42
11 a, b, c	Trifarina kokozuraensis (Asano) × 47
12 a, b, c, d	Miliammina etigoensis Asano & Inomata × 52
13 a, b	Sigmoilopsis schlumbergeri(Silbestri) × 52
14 a, b	Haplophragmoides compressum Le Roy × 26
15 a, b	Cyclammina japonica Asano × 10
16 a, b, c	Goesella schencki Asano × 24
17 a, b	Cyclammina incisa (Stache) × 14
18 a, b	Pullenia bulloides (d'Orbigny) × 42
19 a, b	Gyroidina soldanii d' Orbigny × 20
20 a, b	Martinottiella communis (d'Orbigny) × 16

(Note) Foraminifera species in the order of age from bottom to top. Figure following the "X" after each species shows magnification.

Fig. 4.26 Determination of Fossil Zones



(4) Correlation of Fossil Zones

Comparison of fossil zones determined for a certain area or well with corresponding zones of a different area or well is known as stratigraphic correlation by fossil. Since planktonic foraminifera are distributed extensively, drifting along with sea currents, their fossil zones determined as a reflection of sea currents are often found commonly over a wide area, indicating the time correspondence of strata and providing a valuable means for stratigraphic correlation.

As an example of fossil stratigraphy, Table 4.13 shows the distribution of foraminifera in and around the city of Niigata, Table 4.14 that of planktonic foraminifera fossil zones in the oil field region on the Japan Sea side of northeastern Japan. In Table 4.14, the Tertiary system is divided into nine planktonic foraminifera fossil zones. This division is common to all Tertiary systems along the Japan Sea coast ranging from Hokkaido in the north to the San-in district toward the western end of the main island of Japan. And this provides an important key to correlation. The fossil zones dating to the lower Miocene epoch permit worldwide correlation.

On the other hand, the fossil zones of benthic foraminifera chiefly reflect environmental changes at the sea bottom. Therefore, correlation based on benthic foraminifera is not suited for widely separated areas. Divisions of stratigraphic sequence based on electrical logging of lithofacies usually agree with those based on analysis of planktonic foraminifera, but not with those based on analysis of benthic foraminifera.

(5) Ecology

Environmental factors that determine the ecology of foraminifera include seawater temperature, salt content, nutrition, dissolved oxygen, bottom material and sunlight. The most important of them is temperature. Fig. 4.27 shows some change in marine environment with water depth. In bay areas with little or no wave or current, and in depressions in semideep areas, dissolved oxygen is extremely scarce. On sea bottoms in such areas, there live numerous sandy foraminifera.

Since planktonic foraminifera, unlike benthic foraminifera, live near sea surfaces, they are hardly affected by water depth or bottom material but are strongly influenced by seawater temperature.

Table 4.13 Stratigraphic Horizon of Foraminifera Fossils in and Around Niigata City (From Japan Natural Gas Association)

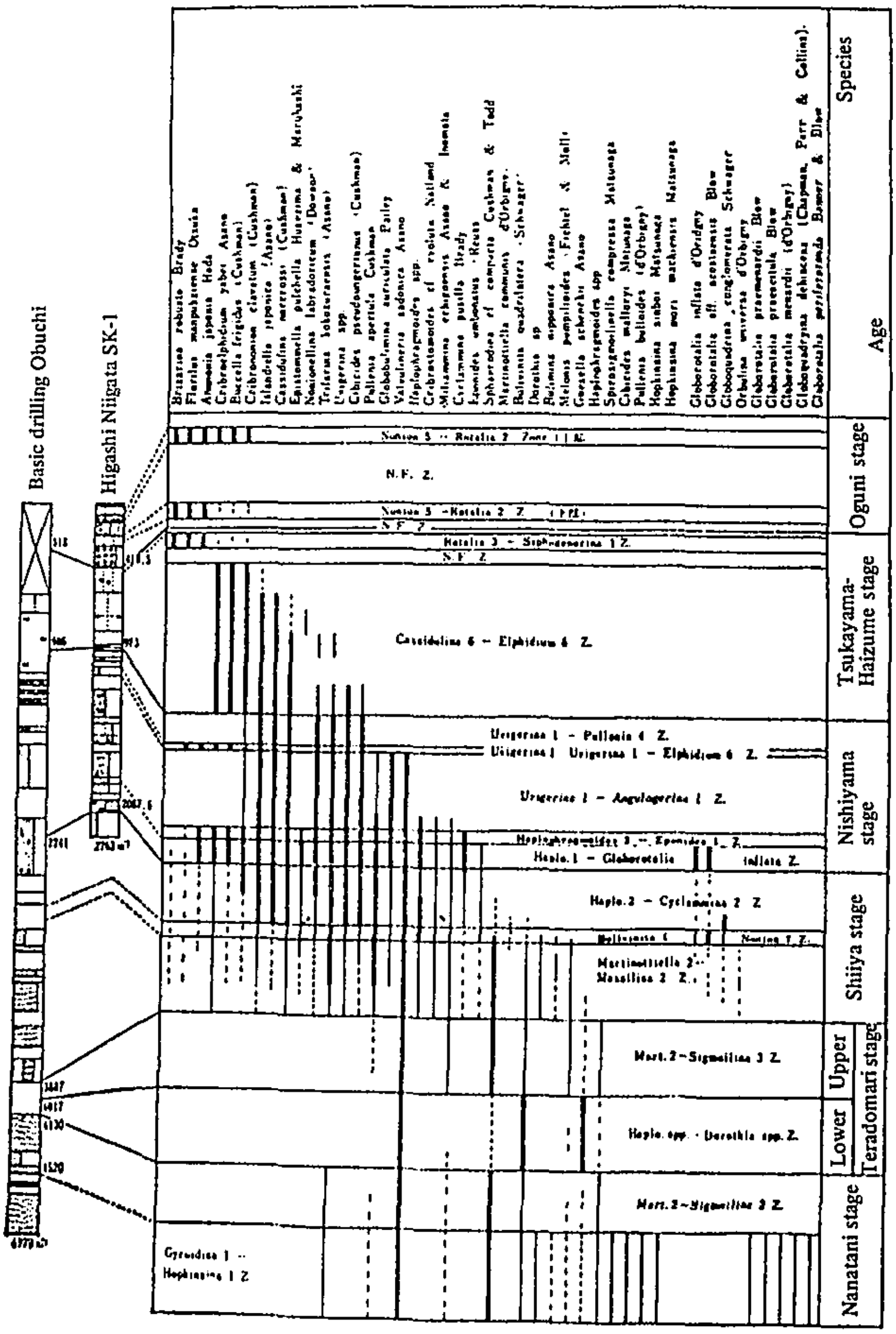
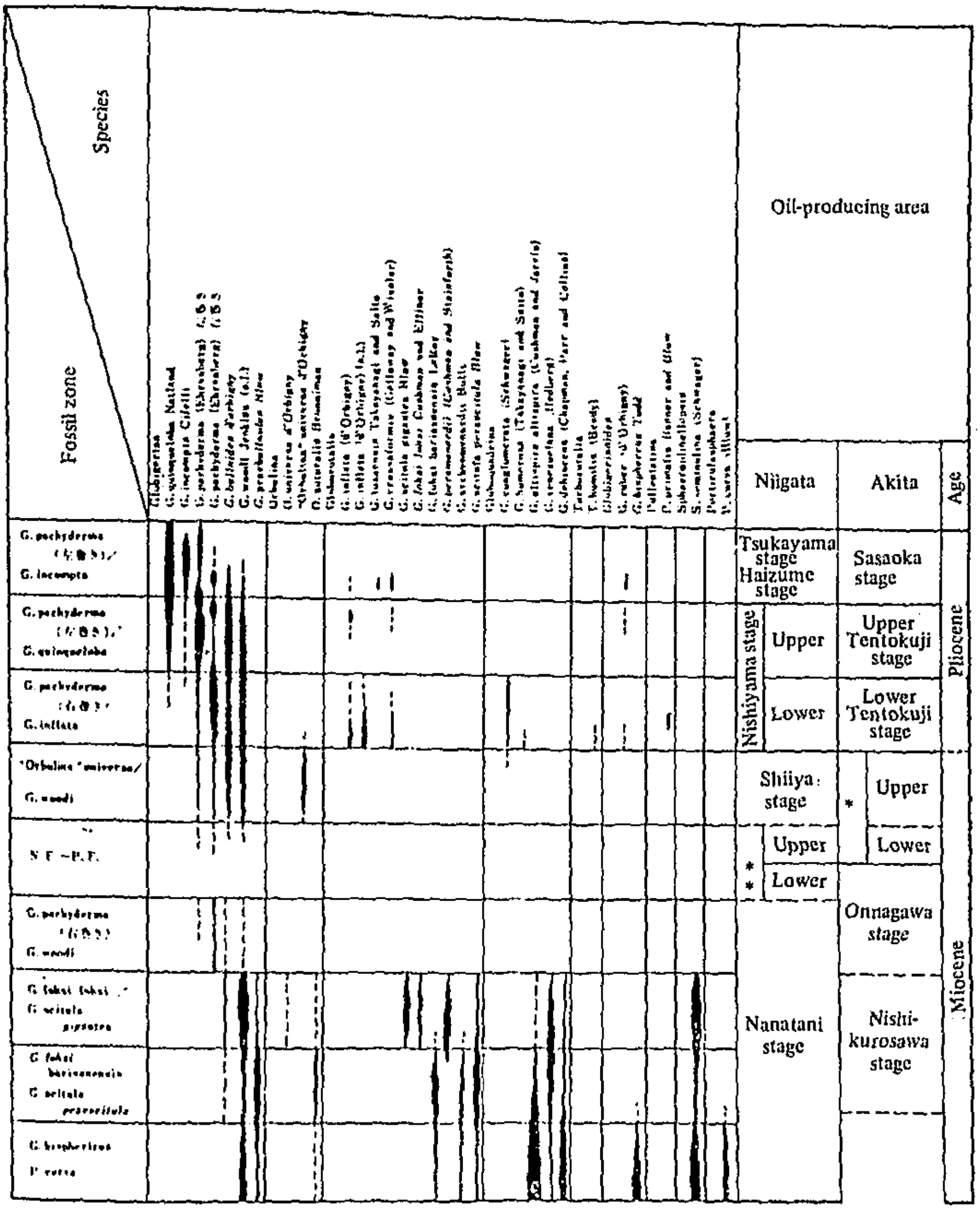
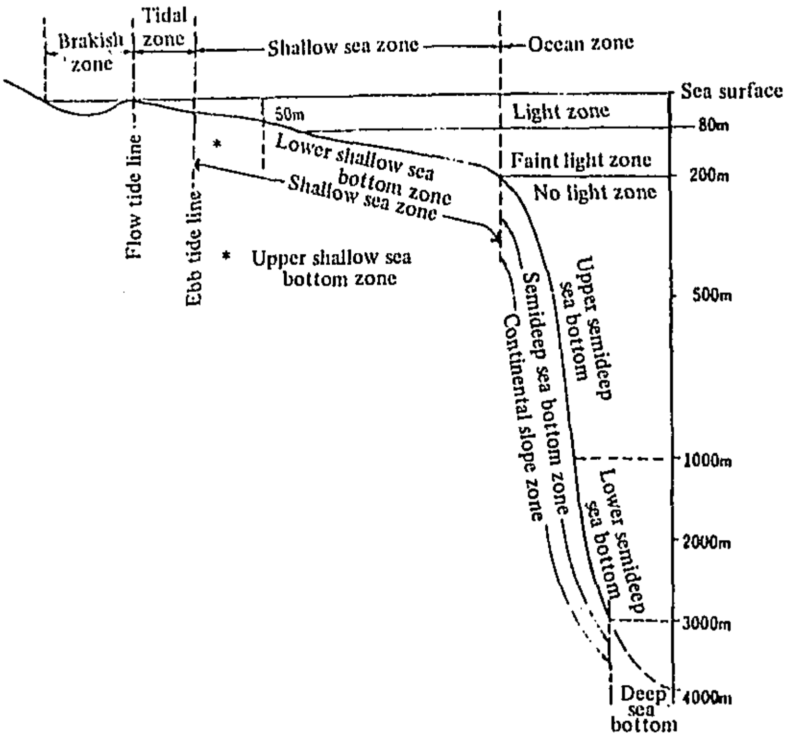


Table 4.14 Planktonic Foraminifera Fossil Zone in Oilfield Area on Japan Sea Coast of Northeastern Japan (From Shimbo, Yonetani)



* Funakawa stage
** Teradomari stage

Fig. 4.27 Environmental Sections of Ocean



(6) Summary

Fossilology and paleontology were briefly explained as they relate to stratigraphic divisions. Foraminifera, which form the nucleus of paleobiogeographical surveys in today's oil exploration, were taken up as an example to describe the method of survey and interpretation of data. In nonmarine formations where no foraminifera are found, paleobiogeographical surveys are directed at pollen, spores and diatoms as important subjects. As a new trend in paleontology worldwide, various modern instruments have been introduced in research and investigation. Electron microscopes are being used for studying nannoplankton and for probing the microstructures of fossils which have previously been investigated for their forms alone. Also, radioisotopes are being employed in analyzing and determining paleo water an temperature and organic compounds in fossils. Japanese paleontologists involved in oil mining are now required to expand their scope of activity so that they can respond swiftly to needs for oil exploration in new areas. They must also determine which of the new techniques they should select and apply in enhancing the accuracy of paleobiogeographical surveys in oil exploration projects.

4.3.1.4 Sedimentological Survey

(1) General

Sedimentological studies in petroleum geology are concerned chiefly with estimation of the environment and form of accumulation of reservoir rock. In 1966 the computer was introduced in dipmenter analysis and ever since highdensity drilling (HDD) has been conducted.

Using the results of such analyses, research in this field has made remarkable progress. In estimating the sedimentological environment, comparative studies must be made of paleontological, geochemical, and petrological (heavy minerals and clay minerals) data. In estimating sedimentary form, grain size analysis data must be studied and compared.

Concerning surface sedimentary structure, Potter and Pettijohn (1963, 1964) have described typical examples, survey methods, etc. In Japan, surveys are being made in the Boso Peninsula, Miura Peninsula, Kyushu coal fields, Nanbayama (Niigata Prefecture), and oil fields, particularly at locations where alternating sand-clay strata of the flysch type are well developed. As for surface, the supply direction of sandstone material is being discussed chiefly on the basis of various markings in the bottom of sand strata. In well data, however, these markings cannot be distinguished, so that HDD is being used as a substitute method to estimate the direction of sand supply and the form of sandstone bodies. Since this work cannot be proved experimentally, much remains to be improved before direct comparisons of well and surface data can be made with any degree of accuracy.

(2) Surface Research Methods and Examples

A. Primary sedimentary structure

In estimating a paleocurrent system, the first step is to carefully observe the sedimentary structure, particularly the primary sedimentary structure.

Primary sedimentary structure means a sedimentary structure formed before hardening during or after sedimentation. It contains beddings, viz., laminations and their external forms and internal structures (patterns), and various markings on upper and lower planes.

Descriptions here will be based principally on Pettijohn and Potter.

Primary sedimentary structure is discussed with regard to the following four items:

- Bedding as the external appearance
- Bedding as the internal structure, composition
- Characteristics of bedding plane
- Deformed bedding

Of these, bedding as related to internal structure and composition is the most important factor in estimating a paleocurrent system. Such a bedding is classified as follows:

① Massive

② Laminated
  Horizontal lamination
  Cross lamination

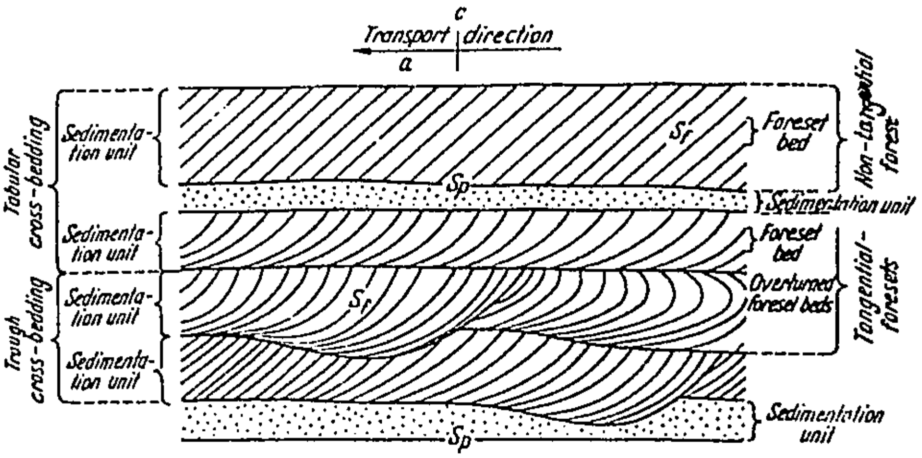
③ Grading

④ Imbricated gravel
  Oriented internal fabric

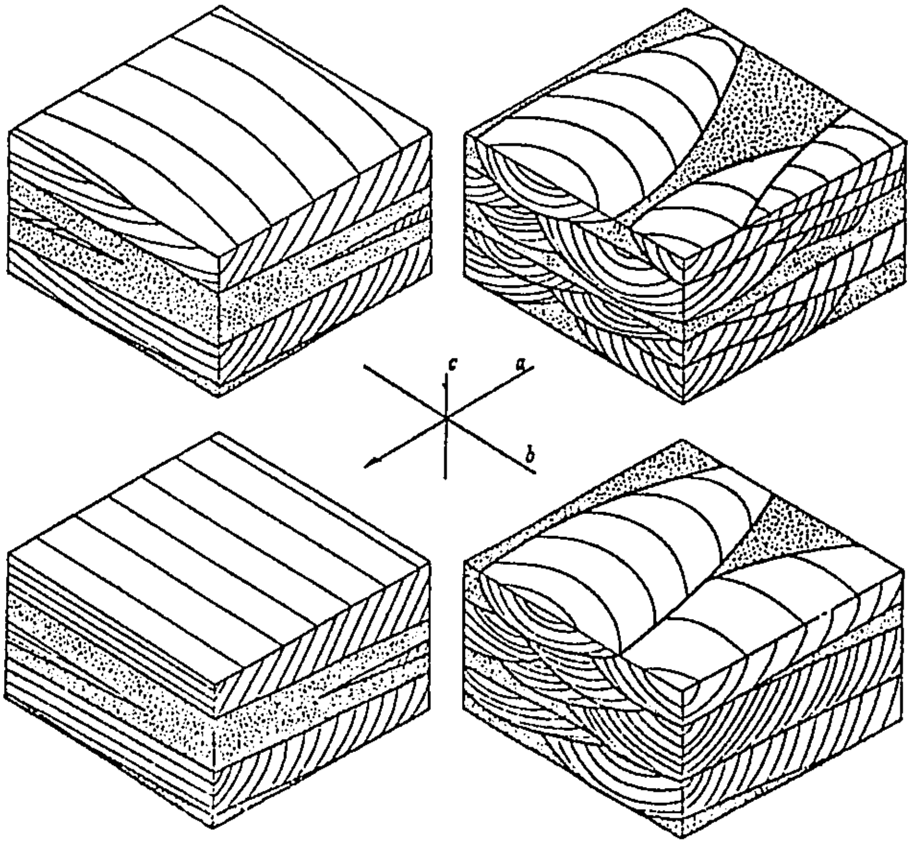
⑤ Growth structures
  Nonclastic rock
  Stromatolitic limestone
  Reef rock
  Travertine

Cross beddings are either tubular or trough-like, as shown in Fig. 4.28. In the foreset bed of the tubular cross bedding, the bottom is either cut at an acute angle by the bedding

Fig. 28



Terminology of cross-bedding

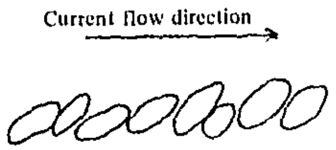


Block diagrams of the two end members of cross-bedding, tabular (left) and trough (right) and standard reference system plane or merges with the plane. The top usually appears as though cut by the bed above. In the trough cross bedding, the foreset bed rarely appears reversed. In complex forms, the lower section of the sandstone bed is massive, the middle section presents a parallel bedding, and the upper section a cross bedding. Cross beddings have been observed chiefly in the sandstone of Shiiya Formation. Such beds are usually well graded and show only a small-scale growth in the very fine sand and silt at the top of the bed. In these cases, it is extremely difficult to take measurements in the true direction of flow (not reconstructed to sedimentation). Particularly in the case of trough cross beddings, the longitudinal direction must be accurately determined and a plane parallel to that direction must be cut out. Failure to do so will render subsequent operations exceedingly complex.

Graded bedding represents the nature in terms of texture. It does not directly indicate the current system involved. Nevertheless, it is an important factor in primary sedimentary structure. In a graded bedding, coarse sand in the lower part of a sandstone bed gradually changes into fine sand or silt toward the upper part. Graded bedding is found characteristically in turbidite, viz. strata in which flysch type sedimentation occurs repeatedly and continuously. Cross beddings observed in the Shiiya Formation were mostly of this type. In this case, the folow energy is estimated to be far smaller than in cross beddings formed in the front margin of the delta. Therefore, it is not easy to determine the true direction of current flow and measured results are violently scattered as shown in the attached map. But cross beddings cannot be overlooked because some of them are closely related to convoluted beddings.

Sedimentary fabric is the pattern of sedimentary grains deposited in parallel to the sedimentary plane. Study of it generally involves microscopic observation, but on the surface, patterns of gravel disposition can be observed visually.

Fig. 4.29



○ Imbricated gravel

As shown in Fig. 4.29, the direction of current flow can be determined from the fact that the longitudinal axis of each pebble is tilted downstream.

○ Edgewise conglomerate

In addition to the above, there is the growth structure often seen in limestone.

Characteristics of the bedding plane are summarized as follows:

- (i) Sole marks
  - (a) Load structures
    - . . . load casts
  - (b) Current structures
    - . . . scour marks
    - . . . flute casts
    - . . . tool marks
    - . . . groove casts
  - (c) Organic markings
    - . . . trails
    - . . . burrowcasts
    - . . . "fucoids"
- (ii) Internal marks
  - (a) Parting lineation

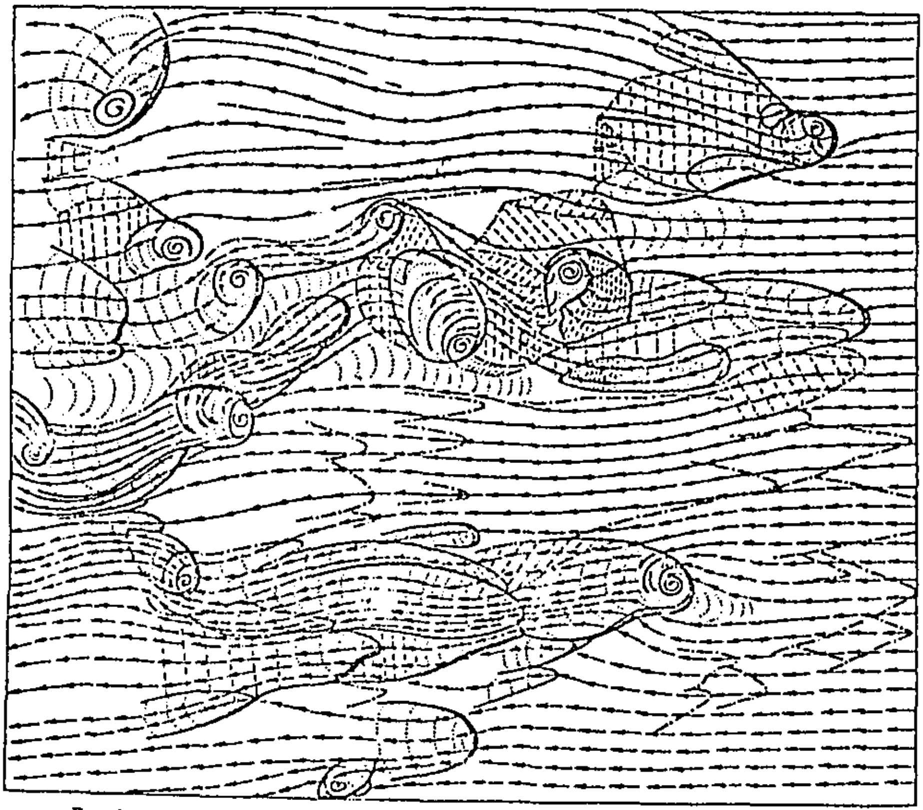
(iii) Top marks
  (a) Ripple marks
  (b) Erosional marks
    ... rill marks
    ... current crescents
  (c) Pits and small impressions
    ... bubble prints
    ... rain prints
  (d) Mud cracks
    ... mud crack casts
    ... ice-crystal casts
    ... salt-crystal casts
  (e) Organic markings
    ... tracks, trails
    ... footprints

Some of the markings that are useful in identifying a paleocurrent system will be discussed below.

Load casts do not directly indicate the direction of current flow but deserve attention in that some of them, originally created by a current, are later subjected to heavy loads which cause them to expand, swell and deform. There are torose and squamiform (Fig. 4.30) load casts. Squamiform load casts have a section of frame structure.

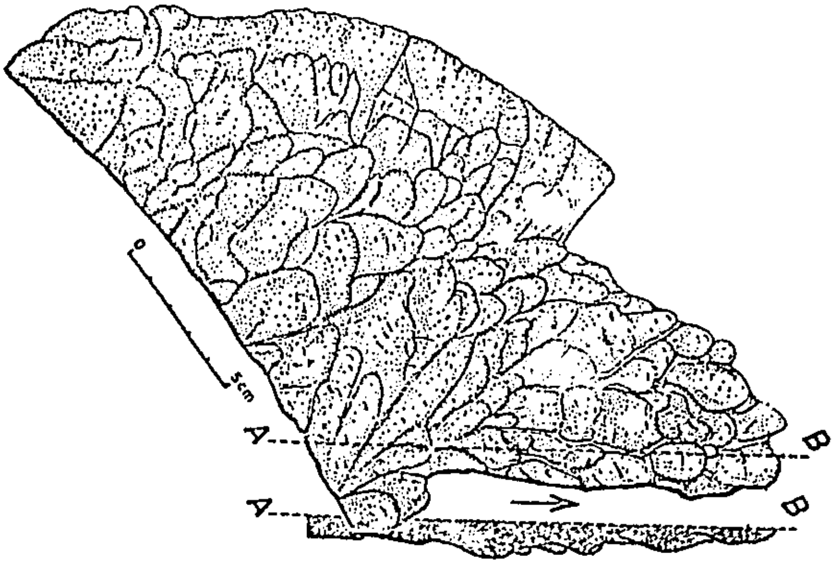
Current marks are made by current energy, on the surface of previously deposited mudrock. Sand accumulates on them to produce casts on the sole of such mudstone (Fig. 4.31).

Fig. 4.31

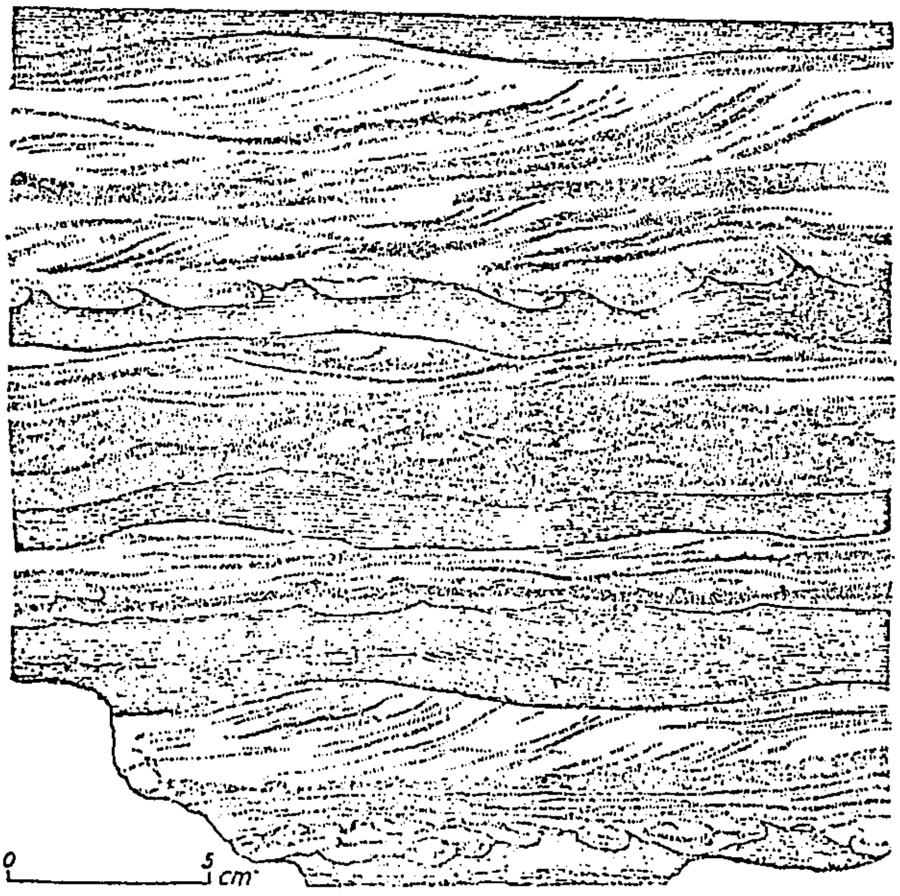


Experimental reconstruction of flow lines on fluted surface (modified from RÜCKLIN, 1938, fig. 12). Sharp boundaries of fluted depressions shown by heavy black crescents; flow lines shown by arrows; depressed flutes shown by dotted concave lines and ridges by dotted convex lines

Fig. 4.30



Squamiform load casts (TEN HAAF, 1959, fig. 33). Picene flysch (Miocene), Cancelli, Apennines, Italy



Flame structures on base of siltstone beds. Note that overturning of mud plumes indicates current flow from right to left as does the small-scale cross bedding. Wilhite formation, Walden Creek group, Ocoee series (Precambrian), State Highway 73, Mineral Springs, Blount County, Tennessee, U.S.A. (Drawn by R.W. B. Davis from U.S. Geol. Survey photograph)

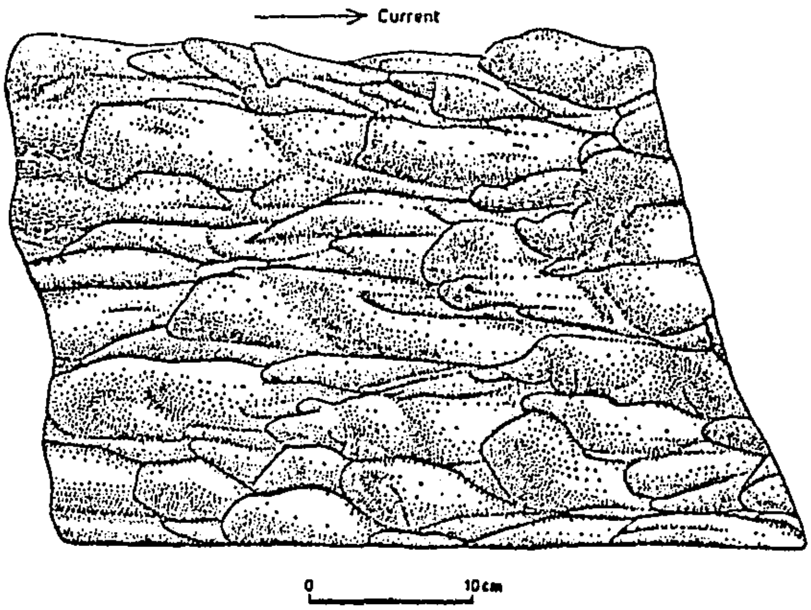
Since great energy is involved, these marks provide a most valuable clue to paleocurrent systems. Depending on how they are formed, they are divided into the following two large categories:

(a) Scour marks

Scour marks are due to the action of current itself. They are represented by flute casts (Fig. 4.32). A strong current creates small channels and washouts.

Fig. 4.32

Linear Structures



Linguiform flute casts (TEN HAAF, 1959, fig. 12). Casts on base of sandstone bed, Marnoso-arenacea, Miocene, Apennines, Italy

(b) Tool marks

These are made when tools of shell, wood, shale or coarse sand scrape against the bottom as they are dragged down current. When the marks are continuous they form groove casts or striation casts. When they are not continuous, skip casts, crush casts or prod casts are formed.

Other marks include roll marks, vibration marks, chevron marks (Fig. 4.33), and ruffled groove casts.

Slide marks are formed when masses of mud, clumps of plants and the like draw parallel lines as they are forced down a current.

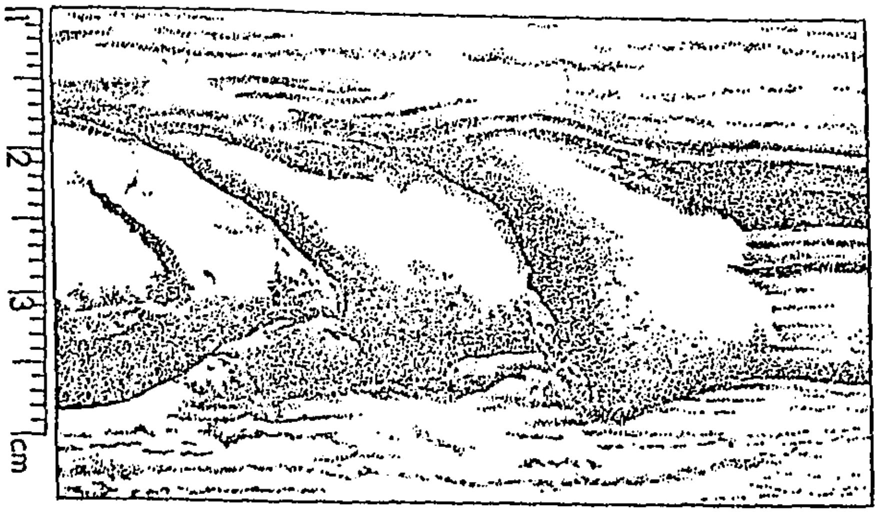
In the recent survey, emphasis of observation was placed on flute casts and groove casts. Other marks could not readily be identified.

Parting lineation is created by erosion along the internal bedding plane. It indicates lines of current flow and patterns of micro cross beddings.

Ripple marks are not limited to sandstones of the geological ages but are found abundantly even today. They come to various forms and sizes. Small ones form regular oscillation ripple patterns, wave ripple patterns and interference ripple patterns. When they are influenced by current, they form irregular linquoid ripple patterns and cuspate ripple patterns.

Large ripple marks that form in waters of alluvial fans and tidal zones are called giant ripple patterns. Marks of larger scale than those found on sand dunes underwater or in the atmosphere are known as sand wave patterns, which occasionally accompany cross beddings.

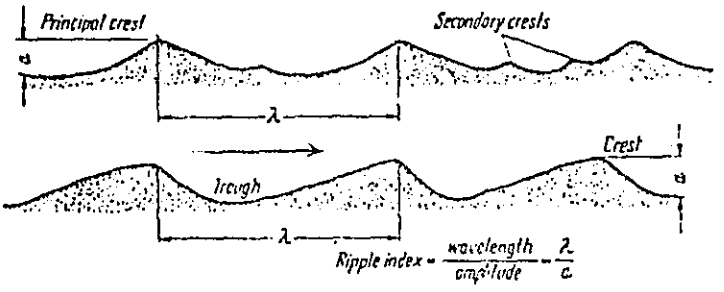
Fig. 4.33



Herringbone or chevron marks (drawn from photograph, Kuenen, 1957, pl. 2C). Note distortion of earlier drag marks. Sherburn flags, Devonian, Taughannock Falls, New York, U.S.A. (sketch by R. W. B. Davis)

As shown in Fig. 4.34, ripple marks have crests and troughs. The lines of crests are at right angles to the direction of current flow. The direction of current flow can be estimated in cases where the waveform is asymmetrical because the upstream wall of the trough is inclined more sharply than the downstream wall (Fig. 4.34).

Fig. 4.34



Wave length, amplitude and ripple index

The current crescent is another indicator of the direction of current flow. A geological dictionary defines it as follows: "A sedimentary structure on the sole of sandstone. It is a horseshoe depression formed by strong erosion in the front (upstream side of a current) of an obstacle such as pieces of shell or gravel on bottom mud. Usually there is a depression in the center, the depression being a cast of the obstacle." It is classified with sole marks on the bottom of a sandstone bed.

Rill marks are long grooves branching toward downstream that form on a sandbeach when water recedes, according to the definition given in a geological dictionary.

In addition, there are patterns and marks that form on the upper surface of strata and thus provide valuable data in determining the horizontal distribution of strata.

Deformed sedimentary structures appear soon after the strata form, even before hardening. Possible causes are foundering, gravity slump, downslope sliding etc. These sedimentary structures rarely show a current system. They will be briefly described below.

(a) Founder structure, load structure

These structures are formed as a result of mechanical reorganization action due to perfect vertical motion (collapse). They are represented by the ball-and-pillow structure, otherwise known as flow-roll or pseudonodule.

(b) Convoluted bedding

This bedding is found characteristically in somewhat course silt and very fine sand. But it is not known how it is formed. Major features are:

- o Folds are extremely irregular.
- o Fault motion is absent.
- o Limited to a comparatively thin single stratum without deformation.

(c) Slumping structure

This sedimentary structure is deformed due to horizontal motion of strata. Of particularly large scale is a structure involving subaqueous sliding, which results in brecciation, faulting or flowage.

(d) Injection structures

In addition to sandstone dike, sill and volcano, there are sand balls and mud balls, or which formation has not been made clear.

(e) Organic structure

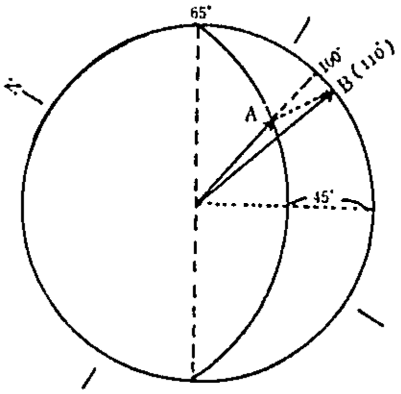
This consists of churned deposits resulting from complete destruction of initial sedimentary structures by organic erosion.

B. Analytical methods

In the field, work starts with stripping and ends with finishing with a knife. First, the status of sandstone and mudstone development is observed from outcrops. By paying attention to depressions and protrusions on the sandstone sole, good markings can be obtained. The dip direction of cross beddings, and the orientation and direction of various sole marks must be restored to those at sedimentation.

(1) Cross beddings (Fig. 4.35)

Fig. 4.35



Example:		
	Dip	30L25°
	Cross bedding	70L30°

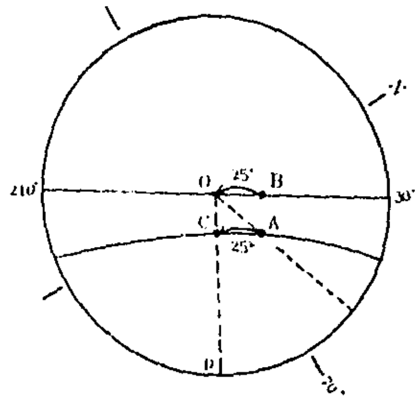
(a) First, project the cross bedding pole (point A) on the upper hemisphere.

(b) The, align the dip direction (30°–120°) with the equator, project the pole (point B) on the upper hemisphere, and restore this point B to point 0 (since it is assumed that the dip at sedimentation is 0°, return 25°).

(c) Also move 25° from point A along the longitude (in the same direction as in (b)) (point C).

(d) Point C obtained is the sought pole of the plane, and is approximately at 123L20 (Fig. 4.36).

Fig. 4.36



(2) Sole mark

The direction of current flow inferred from various sole marks must be restored to dip 0° at the time of sedimentation. But, as in the case of cross beddings, there is the major premise that "folds form along the axis of strike."

Example:	Dip	N65°	E45SE
	Flute cast	100°	
			Outdoor projections on a horizontal plane.
	Groove cast	85° ~ 265°	

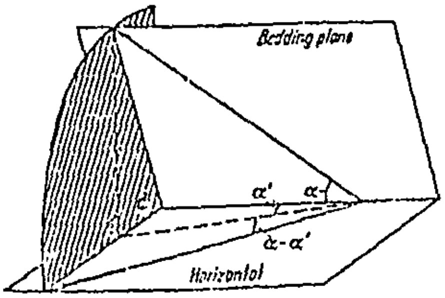
(a) Align strike (65°–245°) with N–S line and project straturm plane on the lower hemisphere.
(b) The, insert the flute cast direction 100° (point A).
(c) Restore to dip 0° along the latitude from point A (point B). This point B is the sought value and the flute cast direction will be 110°.
(d) Restoration of groove cast is done by exactly the same procedure as (a), (b), and (c) above.

The direction projected on the horizontal for the first time in the field will involve a larger error as the dip of the bed becomes sharper. For dips larger than 60°, therefore, the following method was used (Fig. 4.37):

First seek the strike of the bed and also the angle (α) between orientation direction of the mark and the strike using a strike plate then seek the true orientation and direction as it is restored to the horizontal.

The above method was employed this time. With regard to the orientation and direction of sale marks, the values of projection on the horizontal in the field do not differ much from those obtained by true restoration with the use of a stereo-net, as long as the bed dip is less than 40° to 50°.

Fig. 4.37



Relation between an inclined direction and its horizontal projection (modified from TEN HAAF, 1959, fig. 32). The structural dip is d, α is the angle between the strike of the bed and current direction and α' is the angle between the projection of the current direction on the horizontal and the strike of the bed

(3) Method and examples of research in wells

There has been the notion that the dipmeter is for measuring bed dips, but this notion has been rendered obsolete since introduction of the computer for analyses has made high-density analyses possible. And the dipmeter is now being used in examining fine structures-cross-bedding, unconformity disturbance zone and cross-sectional fracture zone. The following are some possible applications of this method including those other than sedimentological applications:

① Application to sedimentology (form of reservoir rocks and their formation)
  o Sedimentation environment of sandstone bodies (transgression type, regression type, sedimentation depth and sedimentation form).
  o Deduction of sand supply direction by means of statistical processing using stereo-net paleocurrent system.

② Application to structural geology
  o Deduction of directionality of fault zone from standard plot.
  o Deduction of orientation of fractures in fault zone with the use of stereo-nets.

③ Application to exploration of oil reservoirs in green tuff and igneous rocks
  o Deduction of fractures developing in igneous rock strata.
  o Deduction of lithofacies of igneous rocks from the pattern of standard plot.
  o Deduction of form of pyroclastic flow on the horizon of green tuff strata (a kind of paleocurrent system of pyroclastic flow)

Among these possible applications, reference here will be made only to ① above.

Since recently petroleum explorers have come to attach importance not only to simple anticline structures but also to complex ones such as stratigraphic blockade (pinch-out of sand, and unconformity), application is desirable to exploration of areas where delta sediments have developed. Sand supply direction, development direction and sedimentation form should be determined by high-density drilling, to use the results as a means of selecting a best location. Various methods have been employed to determine paleocurrent systems. Introduced here is a procedure to determine the paleocurrent system of each sand seam where several sand seams, each about 50 meters thick, are interbedded in a stratum with a thickness of several hundred meters.

ⓐ Obtain mudstone zone values by dipmeter and reduce them on a Semidt net by lower hemispherical projection; perform contouring in 1% mesh and take the center as the theoretical structural dip.

ⓑ Draw a circle of 1ch diameter centered on the point of the structural dip.

ⓒ Out of the dips in the sand seam being analyzed, interpret the ones within the above scope as structural dips, and restore the values of the other points with theoretical structural dips.

ⓓ Plot the restored dips on Schmidt's net, make another contouring, and determine the most frequent direction and inclination. (In this processing, assume the following: Regard all the dips other than structural dips in sand seam as cross-bedding, and consider that they represent the flow direction of paleocurrent. Assume there is no disturbance by faults in the sandstone seam.)

(4) Method of interpreting geological phenomena by dipmeter

① Summary

High density calculation has come to be used in recent dipmeter analyses, in order to make clear sedimentological and structural forms of strata. Various stratigraphical patterns of dips of the dipmeter are clearly defined irrespective of the depth of the strata. This method is particularly valuable with regard to parts of great depth which baffle conventional seismic prospecting technology. Faults can be distinctly confirmed from the direction of dip and strike. Also channel bars and unconformity can be determined by characteristic dip patterns. Clarification of the distribution of complicated channels has been an indispensable means for effective development of the deep oil fields of South Louisiana. Also by defining foreset bed, the patterns of delta sedimentation are made clear from the results of dip calculation. By dip analyses obtained from sedimentation on the face of an irregular reef, talus slopes and a stratum subjected to differential compaction, the location of a reef structure and its form are ascertained.

In some cases the presence of shale diapir has been confirmed. Computer processing of dipmeter data followed by dip calculation at one foot intervals is considered to be particularly appropriate to the study of such problem as abovementioned.

② Introduction

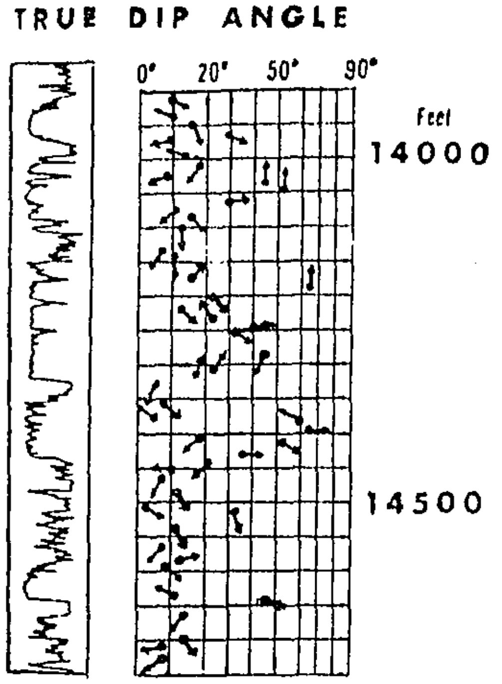
Recent advances in the methods of dipmeter analysis have made it possible to clearly determine, irrespective of depth, structural and stratigraphic anomalies. These methods were first developed in South Louisiana and Mississippi, and their application to many other areas has also attained a fair success. High-density dip calculation, e.g. about 20 calculations per 100 feet, provides detailed information for judging important stratigraphic forms which would be probably missed by other methods. This method is particularly useful in interpretation of deep parts where seismic prospecting is largely helpless.

In this interpretation method, ~~the~~ starting point is the dip calculation for individual bedding planes. In this method, seemingly haphazard dips that "do not fit in with any pattern" are indiscriminately subjected to calculation. However, in not a few cases such dips provide the basis for judging stratigraphic anomalies. This possibility indicates a marked difference from the past method by which the average dip of a zone was obtained from the curve of dipmeter. The past method merely provides data from which to judge general stratigraphic forms. The new analytical method not only furnishes information by which to judge stratigraphic anomalies of various magnitude, but makes it possible to determine structural dips, namely regional dips, more accurately. As will be mentioned later, by averaging dips at certain intervals, an inclination considerably steeper than the real structural dip is obtained in many cases.

To those who are accustomed to zone correlation from the result of dips, a diagram presenting the fine result of dips may appear as though contradictory data are plotted in a haphazard way. Fig. 4.38 is an example of marked variation of angle and azimuth of dips obtained from such an analytical method. Such data are really incomprehensible to the layman, but actually patterns that are characteristic of various structural or stratigraphic anomalies are induced rather easily from these data. Just as an outcrop of a structural or stratigraphic geological form is clearly judged by a trained geologist, so characteristic dip patterns can be judged or classified without much difficulty once one gets accustomed to this method.

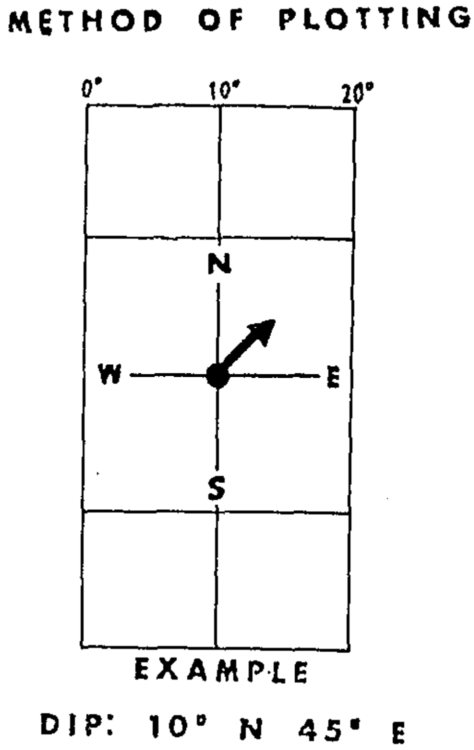
Before explaining the characteristic patterns which define various stratigraphic forms, a few words about how a plotting is made by the dipmeter should be given. Fig. 4.39 illustrates this method. The azimuth and magnitude of dip are plotted on a vertical scale corresponding to the scale of basic resistance curve. The base of the arrow indicates the depth and magnitude of dip. The scale of dip value is shown on the graph. The azimuth of dip is shown by the direction of the arrow. In accordance with the custom, the north is at the top of the diagram. In this example the dip is in N45° and 10° to E.

Fig. 4.38



Example of dip presentation showing high density of computations.

Fig. 4.39



—Depth of formation and magnitude of dip indicated by base of plotted vector. Azimuth of dip indicated by direction of arrow.

③ Classification of patterns

Since the magnitude and azimuth of dips are likely to scatter considerably if dip calculation is made for 7 or 8 dips on an average at 100 feet intervals, dips are classified by azimuth and magnitude into some pattern groups, which will make analysis quite easy.

Dips in the case of cross-bedding are usually scattered to a considerable degree, but the following three patterns are the fundamental. The first pattern is composed on comparatively constant magnitude and azimuth of dip; this corresponds to structural dips. The second pattern (A) is the dips which augment with depth; this is related to fault channel bars and reefs. The third pattern (B) is related to foreset bed and unconformity; in this pattern dip decreases in inclination with the increase in depth. Different combinations of the azimuth and magnitude of dips in a constant or gradually changing azimuth results in the formation of a group or pattern.

Patterns A and B may contain many dip marks extending over a range of several hundred feet, or may be formed of two or three arrows over a distance of only 10 to 20 feet. Dips corresponding to crossbedding assume scattered magnitudes and directions. However, these dips have the characteristic of abruptly appearing, not being influenced by the dips of an upper stratum. Once a dip pattern is determined, well columnar sections should be fully put to use in order to judge its geological anomaly. The method can be best explained by giving various anomaly examples, but this would be too technical to discuss here.

Conclusions

Full utilization of the analytical methods as we mentioned in the above can lead to the discovery of big oil-gas fields, and consequently contribute to the reduction of exploration cost by permitting the selection of proper oil wells. These methods may be used as a means of acquiring detailed information entirely inconceivable in the past.

Free use of the experience accumulated by the employment of these methods will enable us to solve complicated stratigraphic problems more easily than before. Also we shall be able to apply these methods to new fields.

4.3.2 Geochemical Survey

4.3.2.1 Survey of petroleum source rocks

(1) General

As mentioned in the chapter on petroleum deposits, development of petroleum source rocks is one of the essential conditions for formation of a petroleum deposit. Petroleum source rocks include lutaceous sedimentary rocks, organogenic carbonate rocks, etc., but in a global view most potential petroleum source rocks are lutaceous sedimentary rocks, namely the sedimentary rocks known as mudstone or shale. Sedimentary rocks which look like petroleum source rocks are extensively distributed all over sedimentary basins and with a certain geological cycle, but not all of them can be considered to be potential petroleum source rocks for petroleum deposits. The decisive factor is in how much quantitative and qualitative capacity they had to form petroleum.

In petroleum exploration, there are broadly two tasks in appraising petroleum source rocks. One is preliminary appraisal of petroleum source rocks in the sedimentary areas to be explored. This is a task to be carried out before exploratory drilling and is confined to onshore work. In many cases, in parallel with a geological survey on the surface, several routes are selected, a geologist takes about 1kg each of samples which are apparently recognized as petroleum source rock (eliminating weathered parts, a fresh part is chosen), in a systematic manner taking into consideration variation of lithofacies in each geological age (in each straturm, occasionally each group unit), and then the samples are brought to the laboratory to be analyzed. If there are signs of oil or gas, these signs are also sampled and analyzed. Ordinarily, the amount of organic carbon, and bituminous substances as well as hydrocarbons are sought from rocks, and appraisal in accordance with a criterion is done on the basis of their contents. In addition, highly advanced analysis for certain special components has come into use recently for qualitative appraisal, e.g. for petroleum maturity and degree of devolution from petroleum. We may say these are new appraisal methods based on an organic geochemical approach to petroleum origins, migration, accumulation and metamorphism. One application of such methods concerns the direct correlation of petroleum and its source rocks. To clarify the correlation between oil indications and nearby petroleum source rocks is important in determining a target zone for exploration. In such work, trace organic components contained in both petroleum and its source rocks play an effective role as correlation indices.

The above is a preliminary and indirect task. The other task is more direct and in the nature of detailed exploration, beginning from exploratory drilling. Offshore work begins at this stage. In case of wells, cores or cuttings are used as samples. Cuttings that are contaminated by invasion of muddy water cannot be used. The contents of exploration are the same as those onshore; if analyses of adsorbed gas and pore water in addition to those in the case of onshore exploration are conducted, the data serve for correlation of gas reservoirs and petroleum source rocks and for clarification of the mechanism of primary migration.

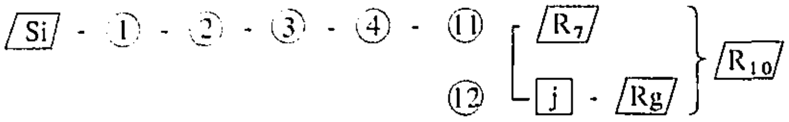
In addition, investigation of chemican composition of rocks, in particular trace components and composition of isotopes (O^{18}/O^{16}, D/H, C^{13}/C^{12}, S^{34}/S^{32}, etc.) will give valuable data for estimating sedimentation environment, origins, diagenesis, and metamorphic process of sediments.

(2) Exploration methods

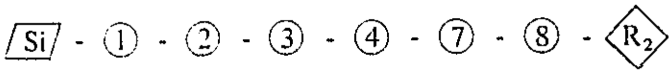
① Ordinary analysis

As we mentioned in the preceding section analysis are usually made for organic carbon (Corg), bituminous substances (called total organic extractable (TOE) as they are usually extracted with organic solvent), and hydrocarbons, in extractable organic matter (Hy). The analysis are done following the analysis flow chart set forth in Fig. 4.40.

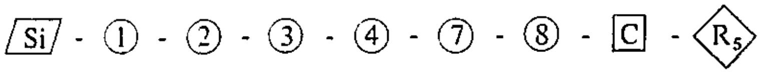
ⓐ Organic carbon (Corg)



ⓑ Bituminous substances (TOE)



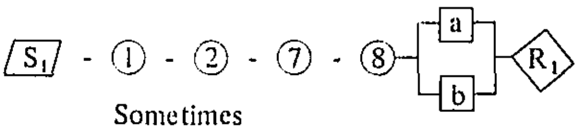
ⓒ Hydrocarbons (Hy)



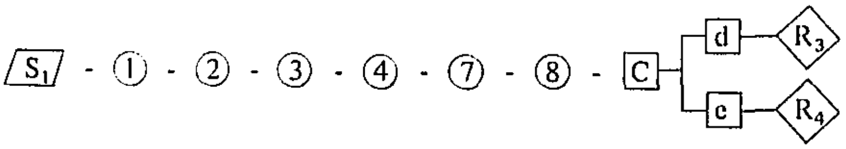
(3) Special analysis

The following analysis are made selectively according to research purposes: Analysis for light-fraction hydrocarbons (C_1 to C_8), medium and heavy normal paraffins, iso-paraffins and naphthenes; for aromatic hydrocarbons and porphyrins; analysis of pyrolysis products and kerogen, analysis for various elements (from hydrogen to uranium); and of stable isotope compositions (δC^{13}, δD, δO^{18} and δS^{34}).

(a) Light fraction hydrocarbons (C_1 to C_8)



(b) Medium and heavy hydrocarbons and porphyrin compounds (n-p, iso-p, Naph., and Porph.)



(c) Pyrolysis products (C_1 to C_8)

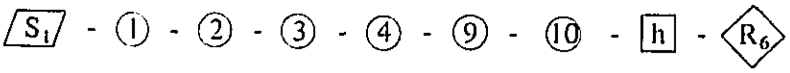
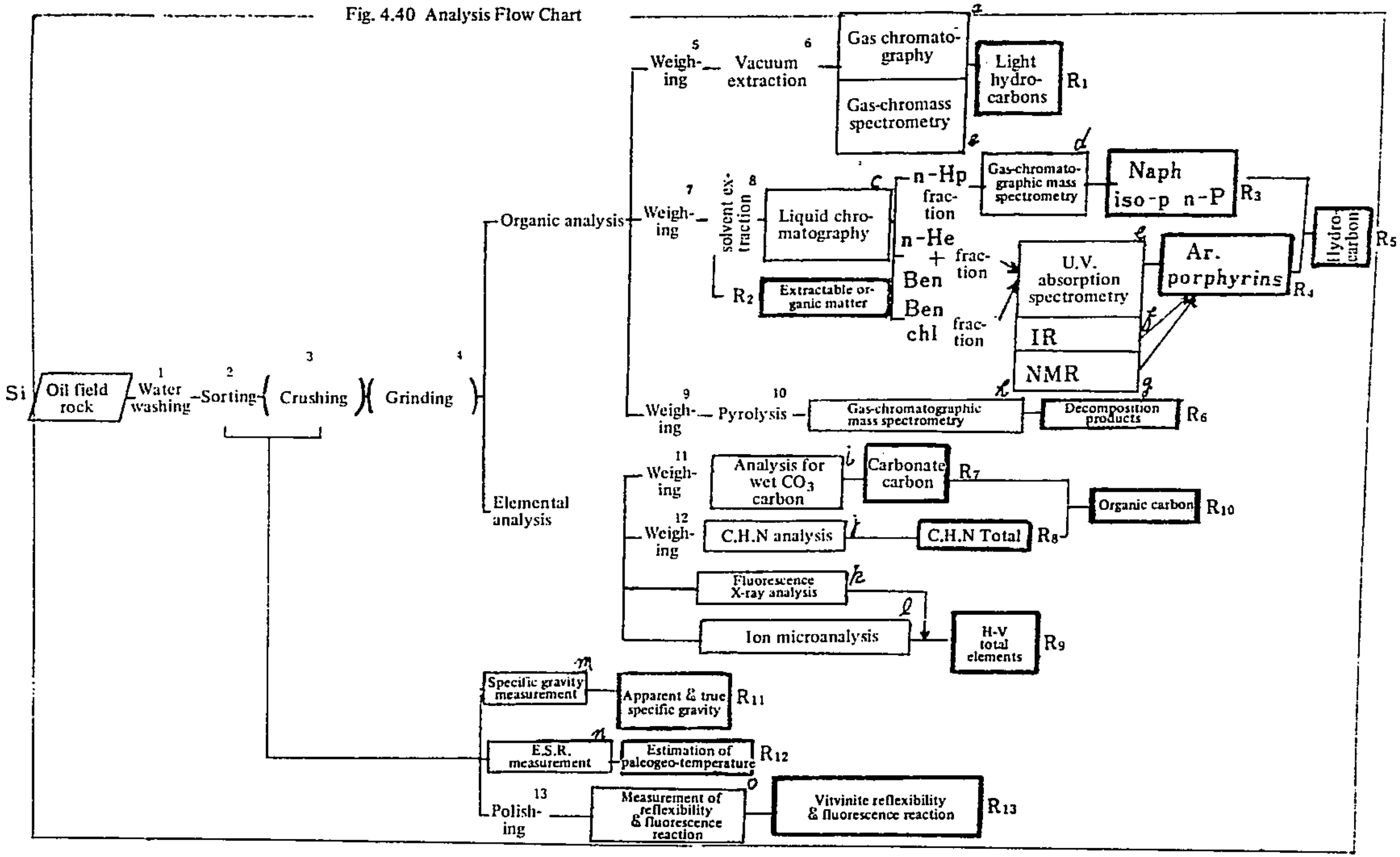
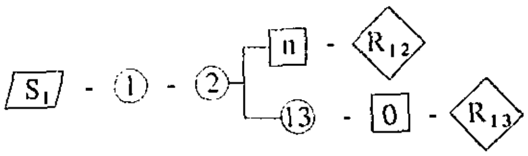


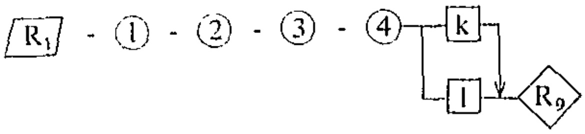
Fig. 4.40 Analysis Flow Chart



(d) Kerogen (C_R)



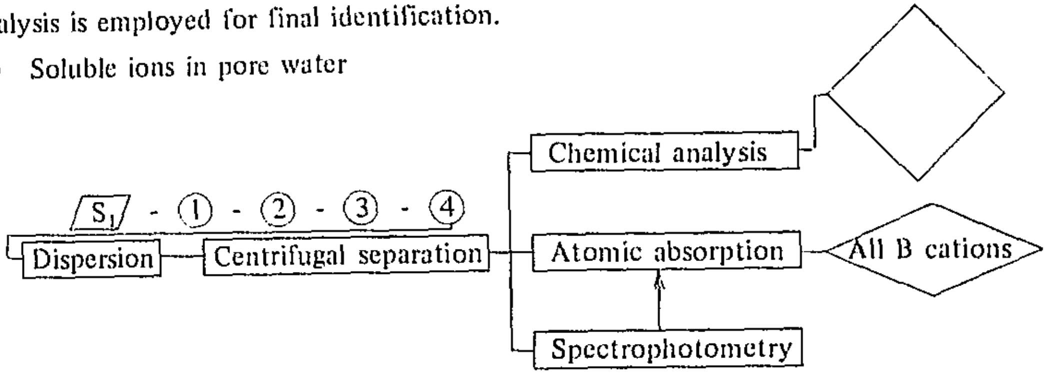
(e) Various elements (hydrogen to uranium)



(f) Stable isotopes (δC^{13}, δD, δO^{18}, δS^{34})

In conducting an analysis for stable isotopes, it is necessary to select proper samples suitable for purposes. While different samples for elemental analysis are required to be pretreated differently for the purpose of analysis, a mass analyzer specially designed for isotope analysis is employed for final identification.

(g) Soluble ions in pore water



(Qualitative)

(4) Evaluation of analytical results

① Evaluation based on the results of ordinary analysis

The criteria of evaluation, differing somewhat from country to country and among different oil firms, may be summed up as follows:

(a) Noncarbonate rocks

Noncarbonate rocks with an organic carbon content of 1% or more (W/W) and a hydrocarbon content of 200ppm or more are considered valuable.

(b) Carbonate rocks

Carbonate rocks meeting the following

Conditions:

Organic carbon content or 1.14% or more when the mineral content is 20% or less, organic carbon content of 0.52% or more when the mineral content ranges from 20 to 40% or below, or organic carbon content of 0.24% or more when the mineral content is 45% or more; and containing 3% or more bituminous substances as against organic carbon are regarded as valuable.

The above criteria are empirical and not theoretically grounded. Tables 4.15 to 4.19 show some actual data, and evaluation criteria adopted by the Shell Group are shown in Table 4.20 for the purpose of reference.

② Evaluation based on the results of special analysis

Here we will confine our discussions specifically to the qualitative evaluation (concerning the maturity and metamorphism of petroleum) of potential source rocks and to the correlation between petroeum and source rocks.

(a) Evaluation of maturity and metamorphism of petroleum

It has been established that the maturity, evolution and metamorphism of petroleum depends almost entirely on thermal conditions. In the evaluation of potential source rocks, too, normal analytical components alone are not sufficient to provide qualitative information on the maturity, evolution or metamorphism of petroleum. Because of this, a number of methods of qualitative evaluation have been evolved.

(i) Evaluation of maturity by analysis for normal paraffin distribution patterns

According to this method, normal paraffin components of source rocks are separated, and subjected to gas chromatography or gas chromatography-mass spectroscopy (GC–MS) to find the frequency of occurrence of normal paraffins as classified by the numbers of carbon atoms. In this way, the maturity of petroleum is investigated according to the distribution patterns of normal paraffins.

Table 4.15 *Noncarbonate carbon content, content of indigenous hydrocarbons boiling above 325°C. and hydrocarbon/noncarbonate carbon ratio of some ancient sediments.*

Age and formation (location)	Average noncarbonate carbon content (%)	Average hydrocarbon content (ppm)	Hydrocarbons/ noncarbonate carbon
U. Mio.--Div. D & E (Ventura and Los Angeles Basins, California)	3.12	1577	0.050
Mio. – Telissa, (Sungei Taham Field, S. Sumatra)	0.89	896	0.101
Cret.—2nd White Specks (Alberta, Canada)	2.02	1572	0.078
Cret.--Graneros (Northeast Colorado)	3.08	1239	0.040
Cret.—LaLuna (La Paz Field, Venezuela, S.A.)	3.67	2360	0.064
Cret.—LaLuna Equivalent (Casabe Field, Colombia, S.A.)	1.54	1146	0.074
Perm.—Leonard (Delaware Basin, Texas)	1.66	875	0.053
Miss.– Lodgepole (Eastern Montana)	0.79	267	0.034
Ord. –Winnipeg (Eastern Montana)	0.53	394	0.074

(After G. T. Philippi, 1965)

Table 4.16 Examples of average composition of organic matter in the Neogene sediments in Japan.

REGION	LIQUID PETROLEUM POTENTIAL	No. OF SAMPLES	EXTRACT %	CHROMATOGRAPHIC SEPARATION, %				
				P + Na	Ar	O-N-S	Res.	HC
Niigata	productive	415	0.097	13.1	8.3	27.4	51.2	21.4
Hokkaido	less productive	153	0.085	9.2	9.3	33.8	47.7	18.5
South Kwanto & Miyazaki	non-productive	126	0.028	7.8	5.5	35.1	51.6	13.3

REGION	LIQUID PETROLEUM POTENTIAL	CARBON CONTENT, %			HYDROCARBONS ppm	HYDROCARBON/NONCARBONATE CARBON
		Total	carbonate	noncarbonate		
Niigata	productive	1.06	0.18	0.86	208	0.0208
Hokkaido	less productive	0.72	0.08	0.64	120	0.0162
South Kwanto & Miyazaki	non-productive	1.11	0.41	0.70	37	0.0046

(After H. Yagishita, 1962)

Table 4.17 Hydrocarbon content and hydrocarbon/noncarbonate carbon ratio of rocks of the Philippines.

BASIN / AGE	MINDORO ISLAND	CENTRAL LUZON VALLEY	ILOILO	SOUTHERN LUZON	CENTRAL* VISAYA	COTABATO*
Quaternary	— —	— —	— —	65 (3) 0.0036	— —	
Neogene	— —	48 (6) 0.0308	50 (21) 0.0057	96 (7) 0.0083	142 (8) 0.0574	90 (8) 0.0384
Paleogene	61 (4) 0.0055	38 (3) 0.0167	— —	— —	— —	
Mesozoic	50 (12) 0.0204	— —	— —	— —	— —	

upper: hydrocarbon content (ppm),
( ) number of samples
lower: hydrocarbon/noncarbonate carbon ratio
unpublished data, by courtesy of Exploration Division, Teikoku Oil Co.

Table 4.18

DISTRIBUTION OF HYDROCARBONS AND ORGANIC MATTER IN NON-RESERVOIR ROCKS

(After HUNT, 1961)

Rock type	*Hydrocarbons (p.p.m.)*	*Organic matter (weight %)*
Shales		
Wilcox, La.	180	1.0
Frontier, Wyo.	300	1.5
Springer, Okla.	400	1.7
Monterey, Calif.	500	2.2
Woodford, Okla.	3,000	5.4
Limestones and dolomites		
Mission Canyon Limestone, Mont.	67	0.11
Ireton Limestone, Alta.	106	0.28
Madison Dolomite, Mont.	243	0.13
Charles Limestone, Mont.	271	0.32
Zechstein Dolomite, Denmark	310	0.47
Banff Limestone, N.D.	530	0.47
Calcareous shales		
Niobrara, Wyo.	1,100	3.6
Antrim, Mich.	2,400	6.7
Duvernay, Alta.	3,300	7.9
Nordegg, Alta.	3,800	12.6

Table 4.19

DISTRIBUTION OF HYDROCARBONS AND ASSOCIATED ORGANIC MATTER IN RECENT AND ANCIENT SEDIMENTS

(After HUNT, 1961)

Sediments	*Hydrocarbons (p.p.m.)*	*Organic matter (weight %)*
clays (Recent)[2]	50	1.5
clays (ancient)[2]	300	2.0
carbonates (Recent)[1]	40	1.7
carbonates (ancient)[2]	340	0.2

[1] Gulf of Batabano, Cuba.

[2] Average of samples from several areas.

As we have already discussed in the section on mineral deposits, we have the CPI values as an index to distribution patterns. CPI, or Carbon preference Indices, represents the predominance of odd-carbon-number molecules over even-carbon-number molecules in normal paraffins.

Bray and Evans of Mobil Oil Co. named this index "CPI," and gave it the following formula (1961):

$$CPI = \frac{2\Sigma_{n=16}^{n=12}\ C_{2n+1}}{\Sigma_{n=16}^{n=12}\ C_{2n} + \Sigma_{n=17}^{n=13}\ C_{2n}}$$

The CPI value of normal paraffins contained in potential source rocks with mature petroleum comes close to 1, or the CPI value for crude oil. It is used for the qualitative evaluation of source rocks. Further, Phillippi (1965) studied the distribution patterns of normal paraffins with 15 to 36 carbon atoms with respect to lutaceous rock of the upper Pliocene and upper Miocene ages in the Los Angeles and Ventura basins and attempted to establish a criterion for the evaluation of potential source rocks on the basis of their relationships to the hydrocarbon/noncarbonate carbon ratio and the analyses of naphthene rings and subsurface temperature. He paid special attention to C_{29} and used $2D_{29}/C_{28} + C_{30}$ as an index to the odd/even ratio of carbon atoms (See Fig. 4.41).

In Japan, too, relevant research and development work has been made in this field by the Japan Petroleum Exploration Co., Ltd. Insti. of Mineralogy, Petrology, and Economic Geology of the Faculty of Physics of Tohoku University. (Dr. Taguchi), the Technology Research Center, Japan Petroleum Development Corporation.

(ii) Evaluation of maturity through measurement of vitrinite reflectance

This method, derived from White's (1915, 1920) carbon ratio theory, is designed to estimate the degree of degeneration of organic matter in rocks on the basis of the carbonization degree of coal.

Thus, the mean maximum reflectance $\overline{R}o$ (%) of vitrinite, a component of coal contained in sedimentary rocks in a dispersed state, is obtained with the aid of a special microscope for measuring reflectance, and the degrees of maturity, immaturity and degeneration are determined by referring this value to the evaluation criterion shown in Table 4.21. Cuttings can serve as samples. Sedimentary rock is sliced by a special method into samples.

Reflectance has a close relationship to paleogeo-temperatures, and rises in proportion to an increase in pal eogeotemperature.

(iii) Evaluation of maturity by the Kerogen-ESR method

An organic substance insoluble in an organic solvent (chloroform, carbon tetrachloride, etc.) contained in source rocks is called kerogen. The concentration of its free radicals is measured by means of an electron spin resonance (ESR) device in order to evaluate the maturity of source rocks.

Table 4.21 Classification of diagenesis zones.

Mean Maximum Reflectance (%)	Carbon (dry ash free) (%)	Zone
		Pre-oil generation
0.5	76	
		Early
0.7	82	
		Main oil generation
1.0	86	
		Late
1.3	89	
		Gas-condensate generation
1.0	91	
		Gas generation

This classification may be slightly changed by further investigation. For practical purposes the value of 1.3% for reflectance or 89% carbon for the boundary between the oil generation zone and gas-condensate generation zone are considered to be the most important. (柴岡他, 1973)

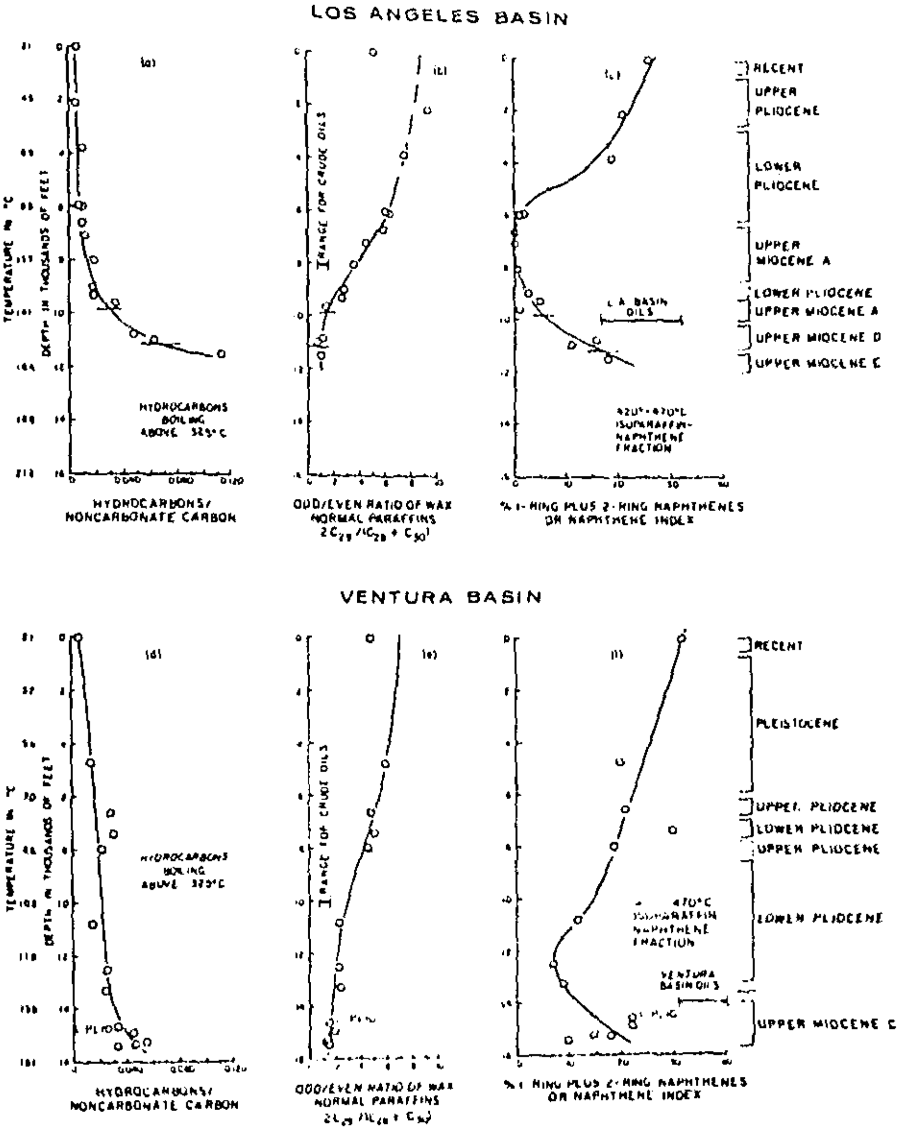
The molecular structure of kerogen is not yet determined, but it is believed to consist of carbonated derivatives ob cellulose, hemi-cellulose and lignin found in the organic matter of living bodies. It is a considerably high-molecular compound with a condensed-polymerized aromatic cycle seat as the nucleus and with alkyl groups as branches in the outermost shell. When it is heated, the branches are severed in the primary reaction to produce free paraffin radicals and free radicals of aromatic rings. The free paraffin radicals immediately combine with hydrogen radicals to produce paraffins, while the aromatic radicals are shielded by the resonance effect of conjugate double bonds, characteristic of aromatic rings, and are preserved stably throughout the geological ages.

Consequently, it is possible to deduce the maximum thermal conditions in the past by determining the spin density of unpaired electrons, and the result of measurement will serve as a parameter in determining the thermal maturity of organic matter. Pusey (1973) studied the relationships of spin density, spin amplitude, etc. to paleogeotemperatures, and by comparing these relationships with the actual occurrence of petroleum, condensates, gas, etc., obtained an evaluation criterion as shown in Fig. 4.42. According to this evaluation criterion, it is possible to decide that no oil deposit exists beyond a certain depth for each geotemperature gradient ("oil phases out"), and as such it can be an effective index in deep oil drilling.

Both (ii) and (iii) above, both of which are based on the relationships of thermal maturity of organic matter to paleogeotemperatures, may be said to be evaluation methods similar in nature. However, it sometimes happens that no vitrinite is contained in sedimentary rocks, so that these methods are not universally applicable. Nevertheless, as the equipment required for these methods is relatively low in cost, they are extensively applied in the Soviet Union, Europe and Australia.

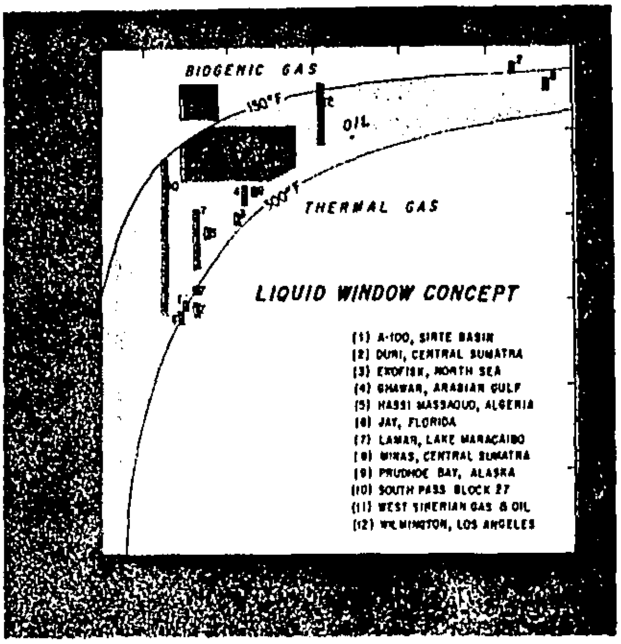
Further, the Kerogen-ESR method is beginning to be introduced in the United States. The ESR equipment is considerably more expensive than the reflectance microscope.

Fig. 4.41



Change of the heavy hydrocarbon/noncarbonate carbon ratio, the normal paraffin odd/even ratio, and the naphthene index with depth, subsurface temperature and age in shales from the *Los Angeles* and *Ventura* basins, California

Fig. 4.42



—Giant fields of Mesozoic and younger age are found with geothermal gradients ranging from 1 to nearly 6° F per 100 feet. A "hot" gradient does not mean hot temperatures, but indicates shallow production (e.g., Minas field). The vertical bar indicates the span of significant production in each field. Oil shows and completions are known at temperatures greater than 300°F, but 99 + percent of the world's oil is found at temperatures cooler than 300° F and most is found at temperatures of 250° F or less (Bavbakov, 1969; Landes, 1964; Rogers et al. 1972)

(b) Evaluation method based on correlation between petroleum and source rocks

If the source rock (in many cases, a stratum or bed) of an oil reservoir discovered is determined, it is possible to find a clue to information on the migration and accumulation mechanisms of the oil reservoir, and this information will be useful in subsequent exploration and development planning.

(i) Correlation method based on the occurrence ratio of perylene and porphyrins

Taguchi et al. (1968), and Kudo (1973) attempted to zone organic matter contained in sedimentary rocks in the oil-producing areas of Japan by combining perylene, a polycyclic aromatic, with Ni-porphyrin and VO-porphyrin, and made a study of accumulation environment and source matter.

Kudo found that there are cycles of several zones with phases of organic matter in the Neogene formation in those regions of Japan which face the Sea of Japan and in the Cretaceous to Neogene formations of Hokkaido on the basis of the volumes of and ratios between perylene (Pe), nickel porphyrin (N) and vanadyl porphyrin, and developed an evaluation method of correlation between petroleum and source rocks on the basis of similarity between them and the volumes of and ratios between these components found in the crude oil that happens to be produced.

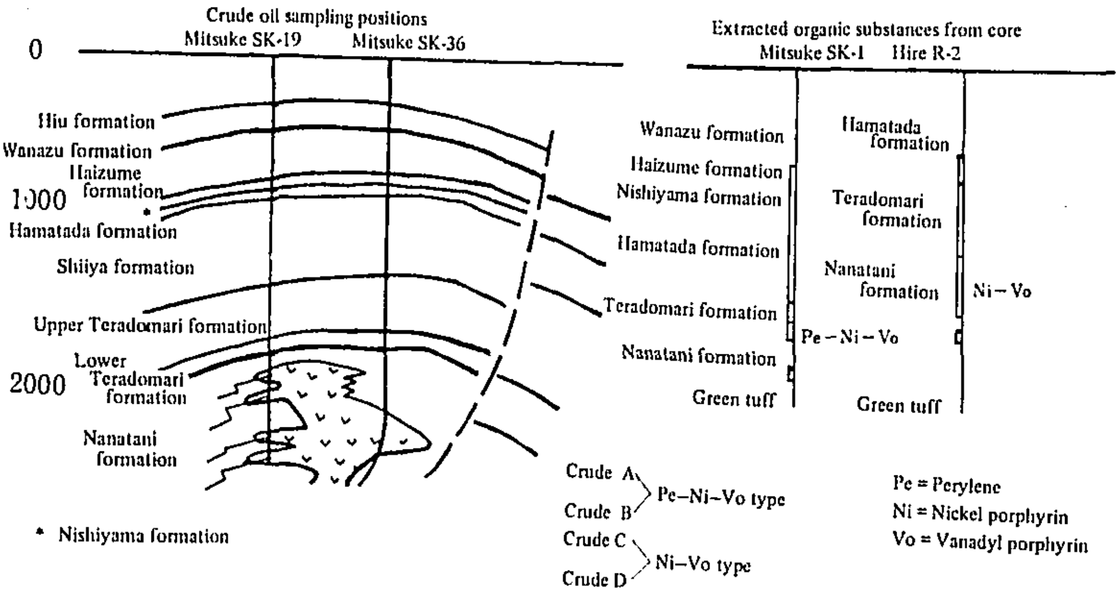
The zones of organic matter are as follows:

I. P-only zone
II. P ~ n zone

III. P ~N zone
IV. N-only zone
V. P ~N ~v zone
VI. N ~V zone
VII. V-only zone

(Small letters show the occurrence of these elements in relatively small quantities, and capital letters their occurrence in relatively large quantities.) Fig. 4.43 shows an example of the correlation method.

Fig. 4.43 Estimation of Source Rocks Based on Porphyrin and Perylene in the Mitsuke Oil Field



(ii) Correlation method based on the occurrence pattern of isoprenoid-type iso-paraffins

Welte (1966) plotted a kind of "chemical fingerprints" (Fig. 4.44) on the basis of the occurrence patterns of isoprenoid-type iso-paraffins, as maturity indices of crude oil. There is a correlation method based on the similarity of these chemical fingerprints to the chemical fingerprints of source rocks. But this method requires fairly large quantities of samples (in the case of rocks, the quantity of samples required is 1kg or more), as well as a sophisticated analysis, so that it is not considered practical at present. But it has an advantage over other methods in that it permits a simultaneous evaluation of maturity. In view of this, it is expected to contribute to improving the method of analysis.

(iii) Correlation method based on the composition of the light hydrocarbon (C_1 - C_8) component

Kudo et al. (1970) made an attempt at a method of correlation between oil (or gas) and source rocks on the basis of pattern analysis of the compositions of light hydrocarbon components.

This method is marked by the advantage that it can also be used for the evaluation of gas reservoirs, in contrast to the fact that the two methods mentioned above are applicable only to oil reservoirs. About 60 kinds of petroleum-type hydrocarbons are known to exist in the carbon number range of from 1 to 8. This is a method of finding a correlation between oil (or gas) and source rocks on the basis of the volumes of and ratios among these components. In the case of gas, it is analyzed as it is by gas chromatography or by the GC-MS method, and in the case of oil, its fractions up to 125°C are analyzed.

As for oil contained in rocks, its light fractions are recovered from rocks with the aid of a vacuum extraction device. In analyzing the data thus obtained, it is necessary to determine the index by statistical processing, including factor analysis, because a number of components are involved.

The results obtained by this method as applied to the basic drilling at "Sorachi" are shown in Table 4.23 as a specific example.

4.3.2.2 Water Research

(1) Outline description

It happens very frequently that only a water layer is struck in test and exploratory drilling. If information on the promixity to oil deposits can be obtained by examining the composition of various components contained in the water in such wells, it would be well worth drilling the wells at great costs. Here lies the importance of water research in oil exploration.

As we have already mentioned in the section on "Petroleum Deposits," water in oil or gas fields is fossil water, sealed together with marine sediments, except in nonmarine sediments. Chilinger (1958) classifies water in oil and gas fields into the following four types.

(1)

Na - SO_4 type . . . . . $\gamma Na - \gamma Cl/\gamma SO_4 < 1$

(γ = per cent equivalent)

Water of this type is inferior in atmosphere-shielding efficiency and is not desirable from the standpoint of occurrence of petroleum.

(2)

Na - HCO_3 type . . . . . $\gamma Na - Cl/\gamma SO_4 < 1$

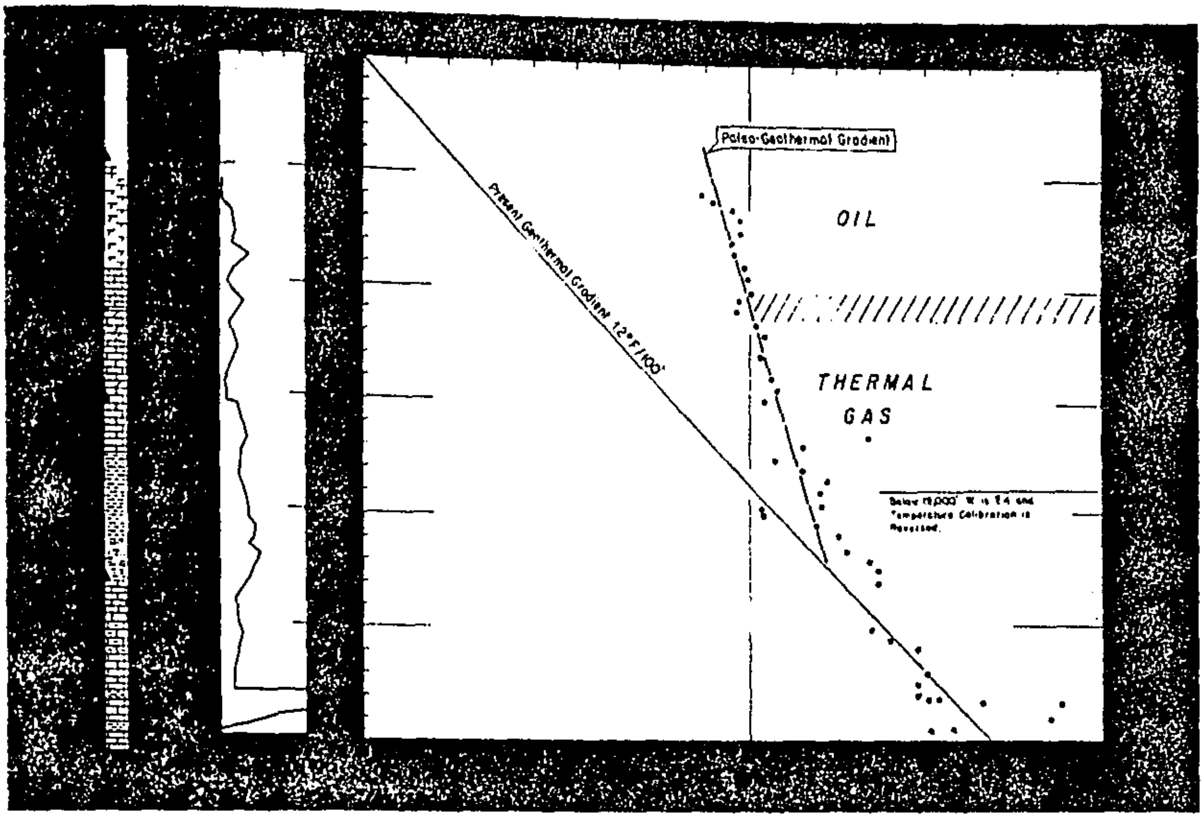
Water of this type is rich in HCO_3 and NaCl of organic origin and scarce of SO_4. It also contains H_2S, naphthenic acid and iodine of the organisms-condensed type. This water is marked by a high promiximity to oil deposits.

(3)

Mg - Cl type . . . . . $\gamma Cl - \gamma Na/\gamma Mg < 1$

Water of this type is low in proximity to oil deposits.

Fig. 4.44



—Paleotemperatures and geochemical data from the world's deepest well, Lone Star Baden 1, Beckham County, Oklahoma. Note that paleotemperatures greatly exceed present temperatures, but that both converge at about 22,000 feet.

(4)

Ca - Cl type . . . . . $\gamma Cl - \gamma Na / \gamma Ca < 1$

Proximity to oil deposits depends on whether or not the water contains I, Br, naphthenic acid and B. In many cases water of this type is strongly mineralized. (a) Naphthenic acid, (b) I, (c) Br, (d) NH_4^+, (e) Ba and Sr are cited as indicators of proximity to oil deposits.

Further, Rittenhouse (1969) sums up his systematic analysis of water from 823 oil and gas fields in the United States and Canada as below.

(a) Concentration orders of various elements

% order	Na, Cl
% or ppm order	Ca, SO_4
100^+ ppm order	K, Sr
1 ~ 100 ppm	Al, B, Ba, Fe, Li
ppb order (most water)	Cr, Cu, Mn, Ni, Sn, Ti, Zr
ppb order (rarely)	Be, Co, Ga, Ge, Pb, V, W

(b) If water from oil and gas fields is compared with sea water on the basis of 35g/liter salinity for the former, the following results are obtained.

(i) Mn, Li, Cr and Sr concentrations are five times higher than those in sea water.
(ii) Sn, Ni, Mg and K concentrations are 1/2 to 1/5 those in sea water.

The above are based on empirical data, but each of them is founded on "case history."

It would be better to use hydrocarbons, naphthenic acid and other direct components of petroleum as indicators, so long as they are to serve as indicators of proximity to oil deposits.

(2) Water research as a direct method of exploration

Here we will discuss a research method based on the examination of hydrocarbons, which are a direct indicator of proximity to oil deposits.

① Hydrocarbon method

Test water used in D.S.T., C.S.T. and other tests in mines is examined.

Hydrocarbons are extracted from about 1 liter test water with the use of xylene. The hydrocarbons thus extracted are processed by a special vacuum distillation apparatus to collect hydrocarbons with the carbon numbers of C_2 to C_7, with a liquid nitrogen trap. The collected hydrocarbons are analyzed by gas chromatography or by the GC-MS method. Fig. 4.24 shows an example of analysis conducted by McAuliffe (1969) of Chevron Research Co.

As shown in Fig. 4.45, we have the benzene method which utilizes the high water-solubility of aromatic compounds. This is a relatively simple method and is extensively applied. In Japan, too, Japan Petroleum Exploration Co. has been employing this method since several years ago. Table 4.24 shows some results obtained by this method.

Table 4.23 Volume and Composition of Gas in Core and Cutting from Basic Drilling "Sorachi"

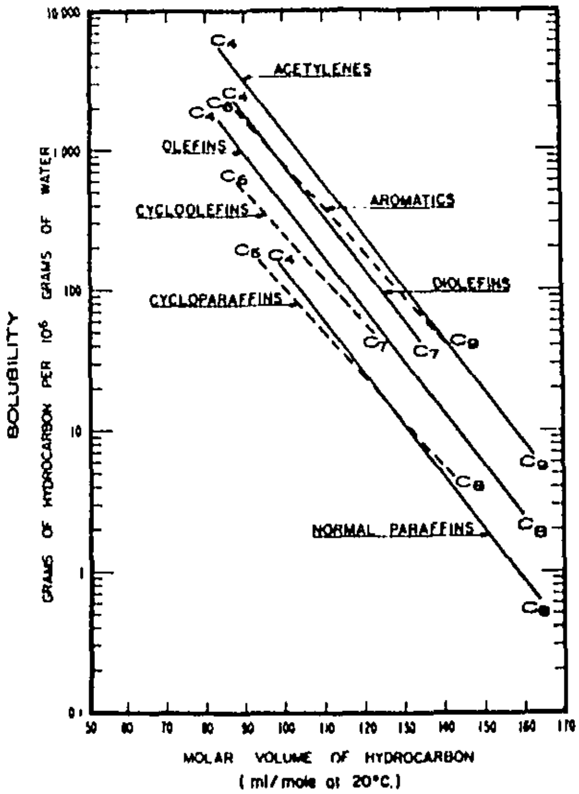
Core sampling depth (m)	Stratigraphic horizon	Rock type	Extracted gas volume	CH_4		C_2H_6		C_3H_8		$i\text{-}C_4H_{10}$		$n\text{-}C_4H_{10}$		$i\text{-}C_5H_{12}$		$n\text{-}C_5H_{12}$		Benzen/MCP								C_2/C_1	C_3/C_1	C_4/C_1	C_5/C_1
			(ml/kg)	%	ml/kg	%	ml/kg	%	ml/kg	%	ml/kg	%	ml/kg	%	ml/kg	%	ml/kg												
753.42 - .77	Ikushumbetsu formation	dgMd.	37.5	2.028	1.011	tr	-	tr	-	0.002	0.001	0.002	0.001	0.003	0.001	0.002	0.001	0.015	0.70	2.92	0.44	8.5	0.23	-	-	-	-	0.179	0.179
375.30 - .43	Horokabetsu formation	Slty. Md·St·	35.0	-		-	-	2.001	-	0.001	-	0.003	0.001	0.008	0.003	0.005	0.002	0.336	1.00	0.43	0.25	-	-	2.17	-	-			
700.89 - 701.09	Noborikawa formation		30.0	1.140	0.433	0.114	0.034	0.474	0.053	0.134	0.040	0.043	0.012	0.028	0.008	0.008	0.002	0.571	0.32	0.29	0.75	-	-	2.48	-	0.083	0.123	0.126	0.026
1,716.30 - .36	Middle Ezo group	Md·St·	30.0	0.088	0.038	0.092	0.028	0.015	0.015	0.014	0.004	0.014	0.004	0.007	0.002	0.006	0.002	0.081	1.00	0.86	1.25	-	0.50	3.25	0.33	1.045	0.380	0.318	0.148
2,130.70 - .95	Lower Ezo group		40.0	25.727	10.295	1.011	0.724	0.419	0.167	0.096	0.022	0.087	0.035	0.028	0.011	0.029	0.012	11.266	1.35	1.05	1.30	1.7	0.16	3.0	3.11	0.070	0.016	0.006	0.003
2,236.30 - .40		Md St	40.0	13.033	7.998	2.800	1.497	0.658	0.387	0.399	0.060	0.143	0.085	0.061	0.037	0.056	0.034	10.198	1.41	0.93	0.84	8.5	0.22	1.9	1.43	0.115	0.045	0.019	0.009
2,366.37 - .50		Sd.st	40.0	0.316	0.190	0.078	0.047	0.070	0.043	0.065	0.038	0.038	0.023	0.026	0.016	0.013	0.008	0.385	2.38	0.34	3.06	-	1.11	11.2	2.0	0.347	0.222	0.326	0.123
2,876.60 - .75	Ikushumbetsu formation	Md·St(Cal 含)	47.5	25.250	22.096	2.460	2.153	1.440	1.260	0.430	0.408	0.180	0.158	0.080	0.070	0.032	0.028	26.131	0.43	0.40	3.30	-	1.00	3.0	3.0	0.097	0.057	0.023	0.004
3,147.78 - .93		mdy·Tf	31.5	0.440	0.337	0.240	0.099	0.162	0.060	0.053	0.019	0.030	0.011	0.014	0.005	0.008	0.003	0.434	0.38	0.57	2.28	-	1.11	3.8	3.3	0.375	0.253	0.138	0.034
[illegible],658.60 - .85	Middle Ezo group	Md.St Slt.st	85.0	21.939	19.486	1.140	0.968	0.387	0.337	0.258	0.090	0.081	0.069	0.027	0.023	0.027	0.023	20.989	1.37	1.00	2.11	-	0.04	3.8	3.3	0.050	0.017	0.006	0.002

Table 4.24

Dissolved hydrocarbon content of four subsurface brines (grams of hydrocarbon in 10^9 g of water)

Peak no. from chromatogram (Fig.3 and 4)	Hydrocarbon	Brine 1 (Fig.3)	Brine 2 (Fig.4)	Brine 3 weathered, light hydrocarbons lost	Brine 4
1	methane	525	1,825	38	5.86
2	ethane	303	240	25	0.41
3	propane	208	23	37	0.58
4	isobutane	89	1.37	10	0.31
5	n-butane	120	5.10	47	0.71
6	isopentane	82	1.50	40	0.48
7	n-pentane	56	1.40	60	0.54
8	cyclopentane+2-methylpentane	34	24.4	75	0.31
9	3-methylpentane	13	0.51	24	0.08
10	n-hexane	17	0.69	60	0.15
11	methylcyclopentane	23	5.19	88	0.12
12	benzene	1,665	10,400	8,650	0.86
13	n-heptane		1.90	5.6	0.33
14	methylcyclohexane		2.76	12.1	0.46
15	toluene	274	4,680	3,340	1.70

Fig. 4.45



Comparison of the solubilities in water at ≈ 25° C of vari
of hydrocarbons, as functions of their molar volumes.

4.3.3 Lithological Methods

4.3.3.1 Reservoir Rocks

(1) Definition and classification

Very roughly speaking, any rock with communicating pores can be a reservoir rock. A rock with hydrocarbons in its pores is called a reservoir rock. Consequently, all sedimentary rocks can be reservoir rocks. More important of them as reservoir rocks are sandstone and carbonate rock. Shales and pyroclastic rocks can be reservoir rocks only under very special conditions.

According to Knebel et al., who analyzed reservoir rocks in all oil fields in the Free World, sandstone accounts for 59% and carbonate rock for 40% of the reservoir rocks. Thus, only less than 1% of the reservoir rocks are accounted for by shales, pyroclastic rocks and the like.

Therefore, reservoir rocks are classified on the basis of actual facts as follows for convenience' sake, though this is not a classification in the strict lithological sense of the term. (1) Clastic reservoir rocks, (2) organic reservoir rocks, and (3) other reservoir rocks.

(2) Kinds of reservoir rocks

a Clastic reservoir rocks

Clastic reservoir rocks are hydrocarbon-containing hardened agglomerations of clastics from the destruction of existing rocks. In the following, we will omit pyroclastic rocks, and deal specifically with sandstone reservoir rocks, which are aqueous clastic rocks, and which are directly related to hydrocarbons.

By sandstone are meant those of the above-mentioned rocks whose grain size is from 1/16mm to 2mm (Wentworth's classification). Therefore, this is a classification that has nothing to do with the composition of sandstone. A chemical composition of sandstone is shown in Table 4.25.

It should be noted here that sandstone with a uniform grain size occurs rarely, and that usually it is a mixture of particles differing in grain size. Further, in most cases it is mixed with tuff in Japan and with carbonate rock in foreign countries. Sandstone mixed with tuff is called tuff aceous sandstone, and that with carbonate rock, calcareous sandstone. Further, accroding to the location where it occurs, it si called marine sandstone, fluviatile sandstone, desert sandstone, etc.

In order that these kinds of sandstone may be reservoir rocks, they are required to be associated with such structures as anticlinal and stratigraphic trap structures. Further, exploration methods methods depends on surface geological surveys and geophysical prospecting. As mentioned above, sandstone accounts for more than half of the reservoir rocks, so that there are ample examples that can be cited, of which two or three are shown here in Fig. 4.46, Fig. 4.47, Fig. 4.48 and Table 4.26.

In addition, sandstone reservoir rocks in the Tertiary formations in the areas of Texas and Louisiana areas on the Gulf of Mexico and in Venezuelan oilfields are well-known. Further, the Burgan oilfields of Kuwait, the world's largest, have Cretaceous sandstone as reservoir rocks. There, oil reservoirs are found in the 800-ft-thick layer of the 1,100-ft-thick Cretaceous sandstone.

The Athabasca tar sand in the Province of Alberta, Canada, which has come to attract wide attention in recent years, has McMurray sand at the base of the Cretaceous formations as reservoir rocks. It is estimated that about 70,000 million tons of sandstone are mineable

Fig. 4.46 Layout of Wilmington Oil Field

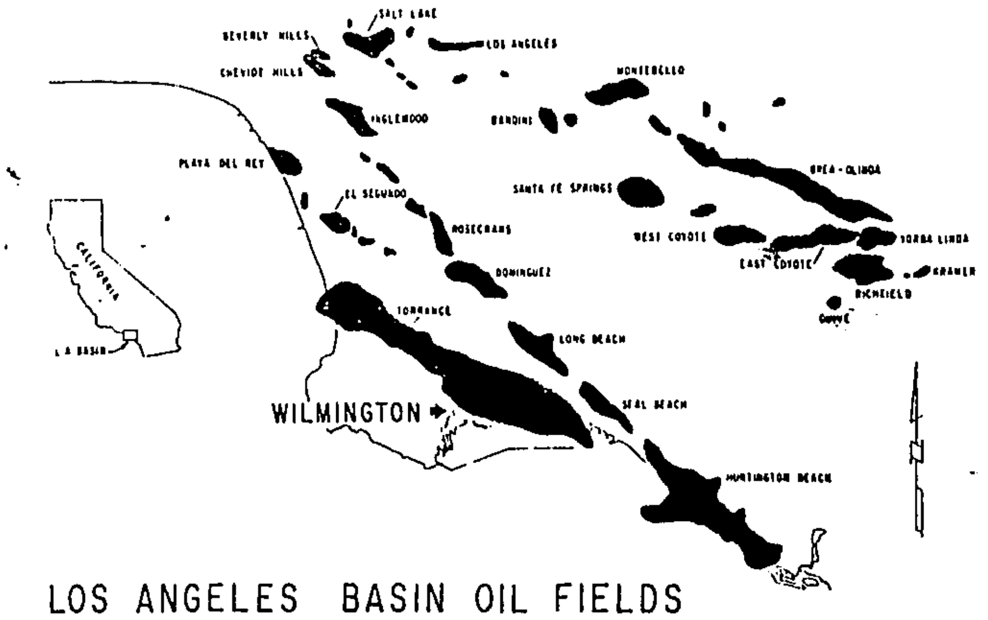


Fig. 4.47 Upper Limit Underground Structure in Ranger Zone of Wilmington Oil Field

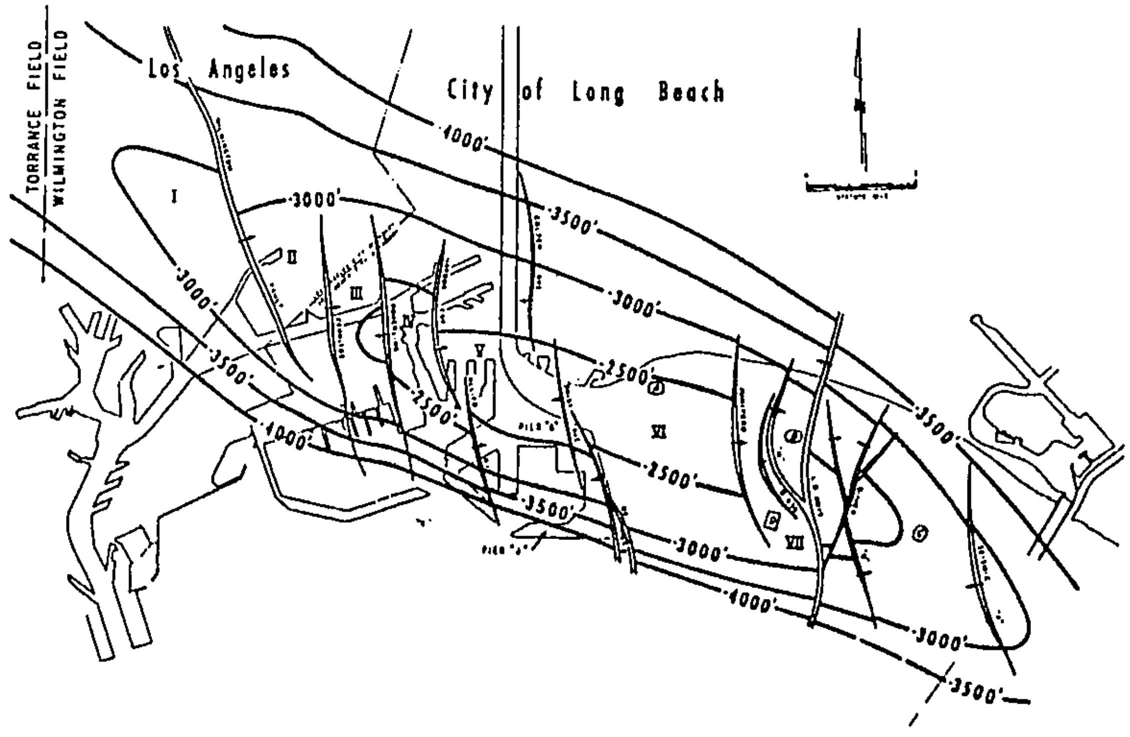


Fig. 4.48 Longitunidal Section of Wilmington Oil Field

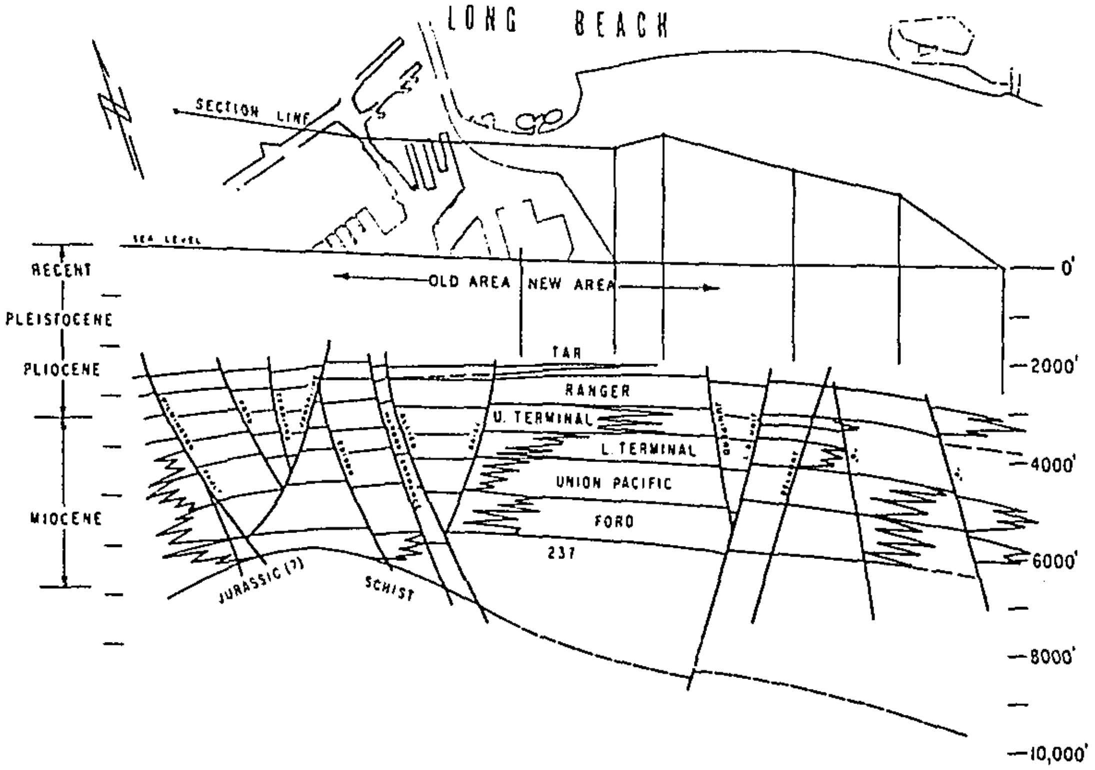


Table 4.25

	SiO_2	Al_2O_3	Fe_2O_3	FeO	MgO	CaO	H_2O(%)
Analyses A =	93.13	3.86	0.11	0.54	0.25	0.19	1.43
Analyses B =	97.80	0.90	0.85	–	0.15	0.10	–

Analyses A	Berea (Mississippian) N. W. Lord
Analyses B	Tuscarora (Silurian) Moore and Taylor Pettijhon Sedimentary Rocks, pp 298

Classification by grain size By Wentworth (sand only)

Classification	Grain size (mm)
very coarse sand	2 – 1
coarse sand	1 – 1/2
medium sand	1/2 – 1/4
fine sand	1/4 – 1/8
very fine sand	1/8 – 1/16

Table 4.26 Properties of Sandstone Reservoir Rocks In Japan

Oil, gas field; oil, gas reservoir	Rock type	Porosity	Permeability	Remarks
Yabase, III formation	Unconglomerated fine sand; screening is good, clay component is relatively small.	35~40	300~600	Based on core analysis.
Higashi-Niigata, 1,440m formation	Tuffy sandstone of fine to medium grains	31~43	118~830	"
Kubiki, I(b,c,e) formation	Tuffy sandstone	30* 27~39**	160~240* 117~311**	*Based on well-logging analyses **Based on core analyses (Reference 7)
Edogawa, Koto sand formation	Unconglomerated fine sand Median grain size: 0.15mm Screening coefficient: 1.30 Silt, clay content 16%	Not measured	2,000±	Based on core analyses (Reference 8)

there. In the Soviet Union, oil is produced from sandstone in the Baku, Maikop, Grozny and other oilfields.

Devonian sandstone at the Bradford oilfields, Pennsylvania, U.S.A., and Middle Ordovician sandstone at Wilcox, Kansas, U.S.A. are well-known as Paleozoic sandstone reservoir rocks.

It is interesting to note that as the proportion of feldspar increases, granite as the base rock is capped by Arkose sandstone or granite wash, which in many cases becomes excellent reservoir rocks. For instance, such reservoir rocks are found at the Panhandle oilfields in Texas, U.S.A., and at various small oilfields in the Province of Alberta, Canada.

b Organic reservoir rocks

The term "organic reservoir rock" is used here in its narrow sense to mean reservoir rocks consisting of carbonate rock, or Levorsen's chemical reservoir rocks. By chemical reservoir rocks are meant chemically or biochemically sedimented rocks which from reservoir rocks. They consist mainly of carbonate rock, or limestone and dolomite. These rocks are very important, in view of the fact that, as mentioned above, they account for about 40% of the world's reservoir rocks and account for 65% of the world's oil and gas output.

Chemical composition of dolomite:

Dolomite is chemically represented by $CaMg(CO_3)_2$; like limestone, it consists of various components. Some analytical values of dolomite are shown in Table 4.28.

Limestone and dolomite as carbonate rocks are not rock names in the strict sense of the terms. Therefore, there are a number of intermediaries between limestone and dolomite, which are classified by M.W. Leighton and C. Pendexter as in Fig. 4.49, and this classification is generally applied.

Description of carbonate rocks:

As will be clear from Fig. 4.49, there are carbonate rocks in different conditions between limestone and dolomite. Therefore, they are described in different ways for different purposes. However, the methods of description may be roughly classified into the following three categories, which are based on:

Table 4.27 Some Analytical Values of Limestone

	SiO_2	TiO_2	Al_2O_3	FeO_3 FeO	MnO	MgO	CaO	Na_2O	K_2O
Analyses A*	5.19	0.06	0.81	0.54	0.05	7.90	42.61	0.05	0.33
Analyses B**	7.41	0.14	1.55	1.80	0.15	2.70	45.44	0.15	0.25

	H_2O	P_2O_5	CO_2	SO_3	Cl	S
Analyses A*	0.77	0.04	41.58	0.05	0.02	0.09
Analyses B**	0.68	0.16	39.27	0.02	–	0.25

* Analyses A : Averages for 345 limestone data, H.N. Strokes
** Analyses B : Crystalline Limestone Brassfield, Silurian, Ohio.
(Pettijhon Sedimentary Rocks pp 384)

(i) grain size and crystal conditions,
(ii) component fossils, and
(iii) sedimentary or accumulated environment.

Color, grain size, and crystal conditions are the necessary and sufficient conditions for the description of carbonate rocks as chemically sedimented rocks, which are usually described as shown in Table 4.29, after the manner of description of sandstone.

On the other hand, the petrological description of reefs or banks as biologically sedimented rocks is somewhat more complex. Here the location of rock forming environment and the kinds of constituent animals are important. The growth of reefs are recognized throughout all the geological ages, with the reefs formed in each geological age presenting themselves as oil or gas fields. However, the constituent animals are characterized differently according to different ages, as shown in Table 4.30.

Of the formations of these ages, particularly important are the Silurian, Devonian and Cretaceous formations as containing oil or gas fields which have been actually worked.

Further, the same reef may differ in constituent fossils and carbonate rocks depending on where it is found. An example of this is shown in Fig. 4.50.

Table 4.28 Some Analytical Values of Dolomite

	SiO_2	TiO_2	Al_2O_3	Fe_2O_3	FeO	MnO	MgO	CaO	Na_2O
Analyses A*	3.24	–	0.17	0.17	0.06	-	20.84	29.58	–
Analyses B**	7.96	0.12	1.97	0.14	0.56	0.07	19.46	26.72	0.42

	K_2O	H_2O	P_2O_5	CO_2	S
Analyses A*	--	0.30		45.54	-
Analyses B*	0.12	0.63	0.91	41.13	0.19

* Analyses A : Knox Dolomite (Cambro · Ordovician)
Morrisville Ala, W. F. Hillebrand
** Analyses B : Niagaran Dolomite (Silurian) D. F. Higgins
(Pettijhon Sedimentary Rocks pp 418)

Fig. 4.29

	Transported Constituents	Authigenic Constituents	
64 mm	Very coarse calcirudite	Extremely coarsely crystalline	
16 mm	Coarse calcirudite		
4 mm	Medium calcirudite		4 mm
1 mm	Fine calcirudite	Very coarsely crystalline	1 mm
0.5 mm	Coarse calcarenite	Coarsely crystalline	
0.25 mm	Medium calcarenite		0.25 mm
0.125 mm	Fine calcarenite	Medium crystalline	
0.062 mm	Very fine calcarenite		0.062 mm
0.031 mm	Coarse calcilutite	Finely crystalline	
0.016 mm	Medium calcilutite		0.016 mm
0.008 mm	Fine calcilutite	Very finely crystalline	
0.004 mm	Very fine calcilutite		0.004 mm
		Aphanocrystalline	

Fig. 4.49 Classification of Carbonate Rocks

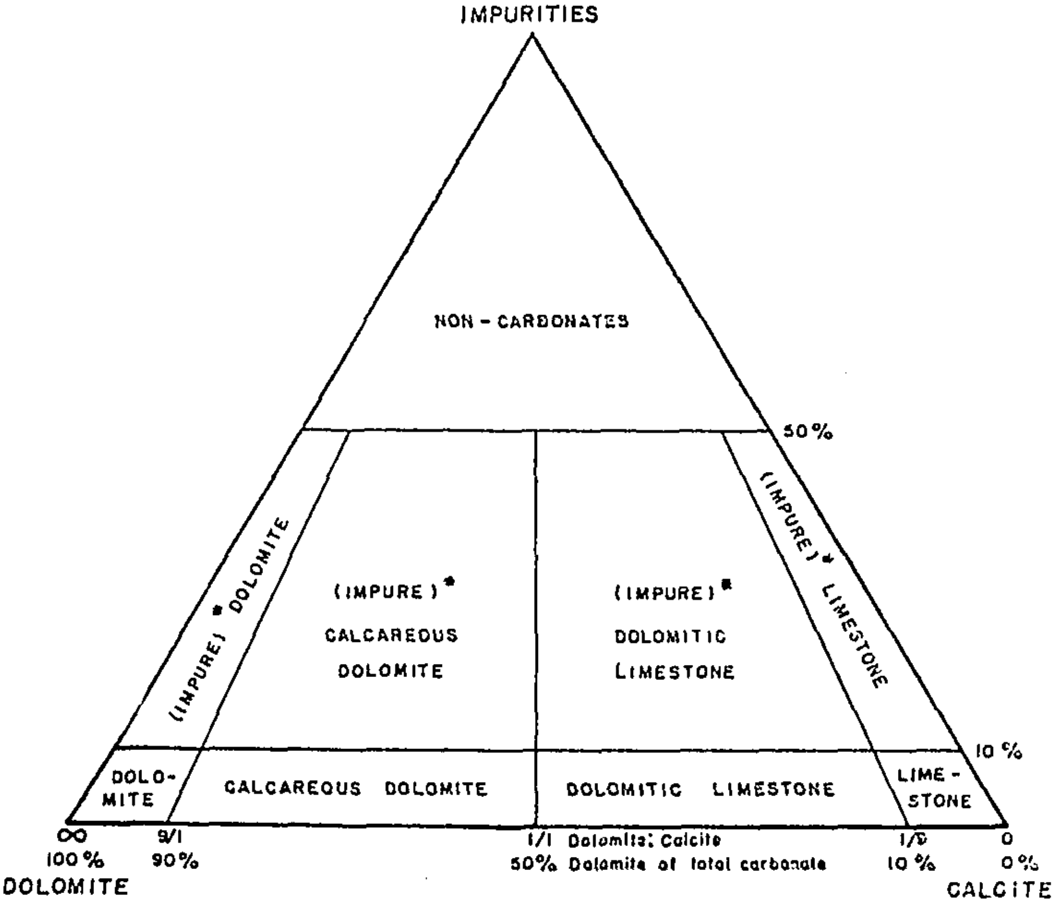
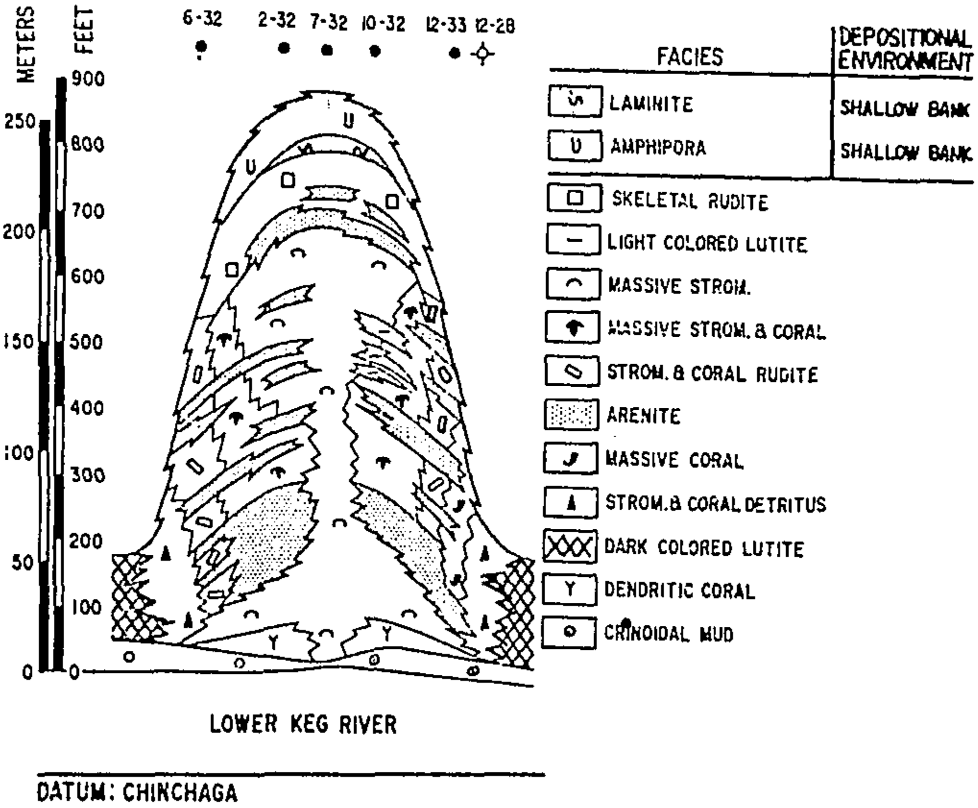


Table 4.30

a.	Cambro-Ordovician	Sponges and Stromatolitic algae
b.	Silurian	Stromatoporoides and tabulate corals
c.	Devonian	Tabulate corals, Stromatoporoids, Colonial rugose corals corals, ryozonans
d.	Mississippian	Crinoids, bryozoans
e.	Pennsylvanian	Tabular foraminifera, platy algae.
f.	Permian	Sponges, stromateporoids, stromafolic algae, tabulav foraminifera, brachiopods
g.	Triassic	Hexacorals, stromato povaids
h.	Jurassic	Hexacorals, stromataporoids, red algae.
i.	Cretaceous	Hexacorals red algae
j.	Tertiary and Recent	Hexacorals, red algae.

Fig. 4.50 Fossils and Carbonate Rocks Constituting Reefs



Forms of pores in carbonate rocks:

The forms of pores in carbonate rocks, which are important from the standpoint of the science of oil deposits, are extremely complex unlike the forms of pores in sandstone. The basic forms of pores in the former are summed up in Fig. 4.51.

Examples of carbonate reservoir rocks:

(1) Asmari limestone of Iran

Limestone in Asmari, in the southwestern part of Iran - - Fig. 4.52, (Tertiary, Oligo-Miocene) - - is known as a first-rate reservoir rock of the world. But normally its porosity is very small at several per cent. However, thanks to the development of favorable fissures, its productivity is very high. Of the oil fields at Asmara, the Agha-Jari oilfield has about 40 production wells yielding 1 million barrels of oil daily. Of these wells, the more productive yield 80,000 barrels each daily. The volume of mineable oil in this oil field is estimated at 950 million barrels (Fig. 4.53).

(2) Keg River dolomite of Canada

The Rainbow oil field, discovered in the northwestern part of the Province of Alberta, Canada, consists of a complex of about 70 pinnacle reefs and atolls (Fig. 4.54), and as shown in Fig. 4.55, its porosity is relatively small. However, thanks to its large pay thickness and high comminicability, it is a very important oil field.

c Other reservoir rocks

Tuff: Tuff breccias as oil or gas reservoirs are not known abroad, but are rather common in Japan.

For instance, at the Yatsuhashi oil field, all the oil reservoirs below layer VII are almost all found in tuff (rhyolite or andesite). Of these reservoirs, the porosities and permeabilities at layers VIII and IX are as shown in the following table.

	VIII 2,3,4	IX 1,2
Average porosity (%)	25.5	25.6
Average permeability (md)	4.9	4.5

Tuff, containing gas cavities such as in pumice, in addition to intergranular pores, is believed originally to have been highly porous and permeable, and its actually low porosity and permeability are considered to be due to secondary compaction and cementation. Further, it is believed that tuff of this kind (particularly rhyolite) has been turned more or less into benonite (or montmorillonite).

Volcanic rocks: Included in this category are volcanic rocks and agglomerates. It is rarely in foreign countries but not so in Japan that oil or gas reservoirs are found in these rocks. For instance, the Mitsuke tuff of the Mitsuke oil field consists of lavas of dacite or plagiorhyolite and tuff and tuff breccias of the same quality. According to a core analysis, its porosity is 0.3 – 34% (according to well logging, about 6 – 30%), and its permeability 0 – 360md. However, apparently fissures are well-developed in both lavas and pyroclastic rocks. Further, in the gas fields at Katagai, Sekihara, Kumoide and other places, (dacitic) andesitic agglomerates and lavas form main gas reservoirs. Intergranular pores in agglomerates, fissures and pores in lava and agglomerates may be suggested as pores in these reservoirs.

Fig. 4.51 Basic Porosity Types of Carbonate Rocks (Cross section)

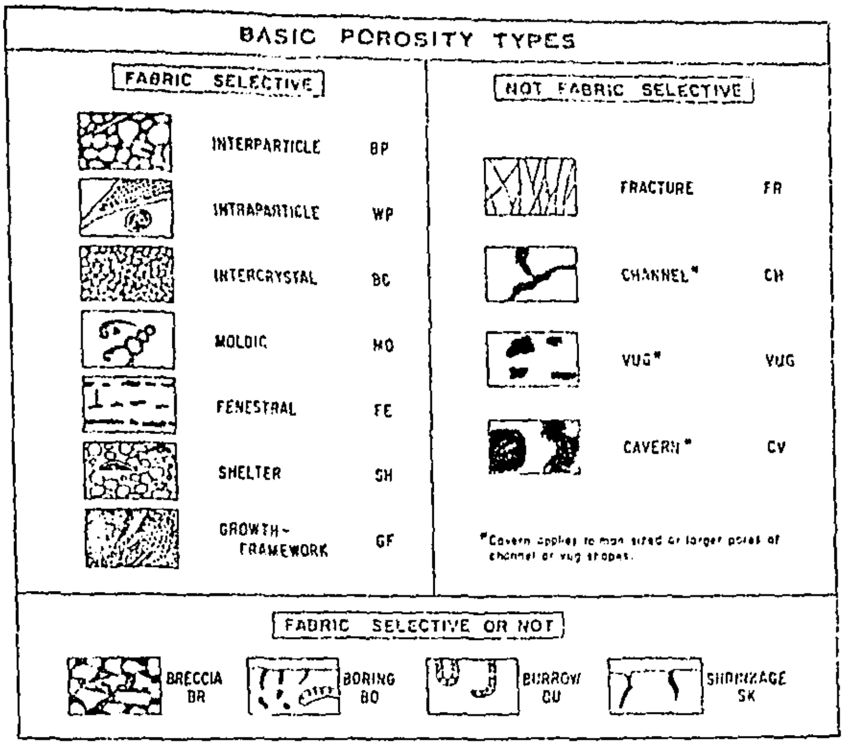


Fig. 4.52

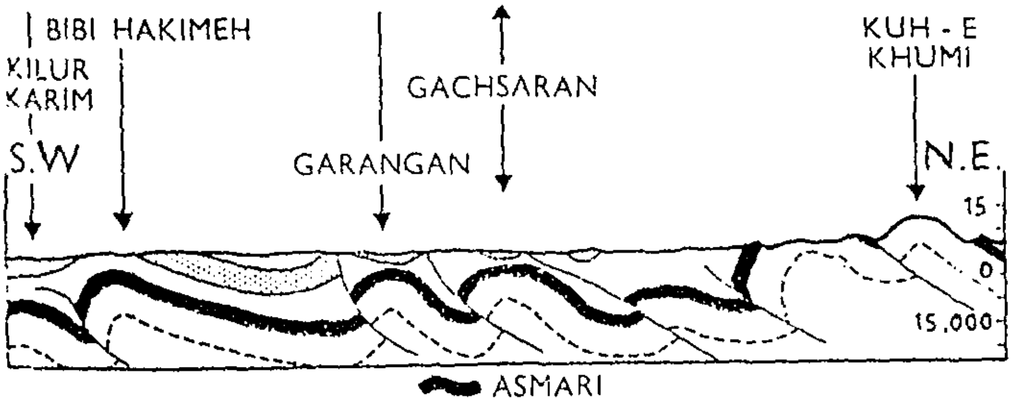


Fig. 4.53 Location of Iranian Oil Fields

Fig. 4.54 Rainbow Oil Field (Devonian)

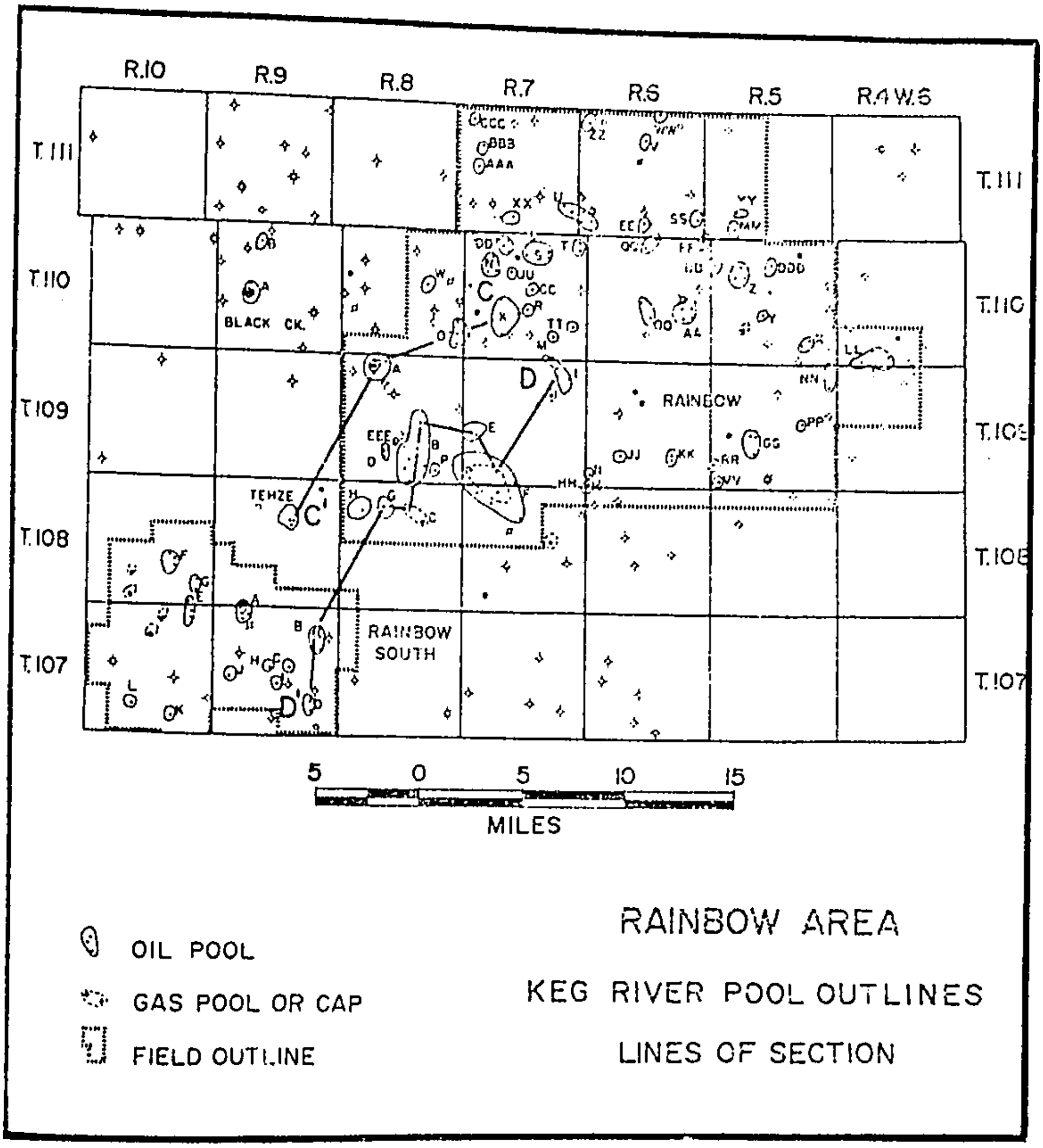
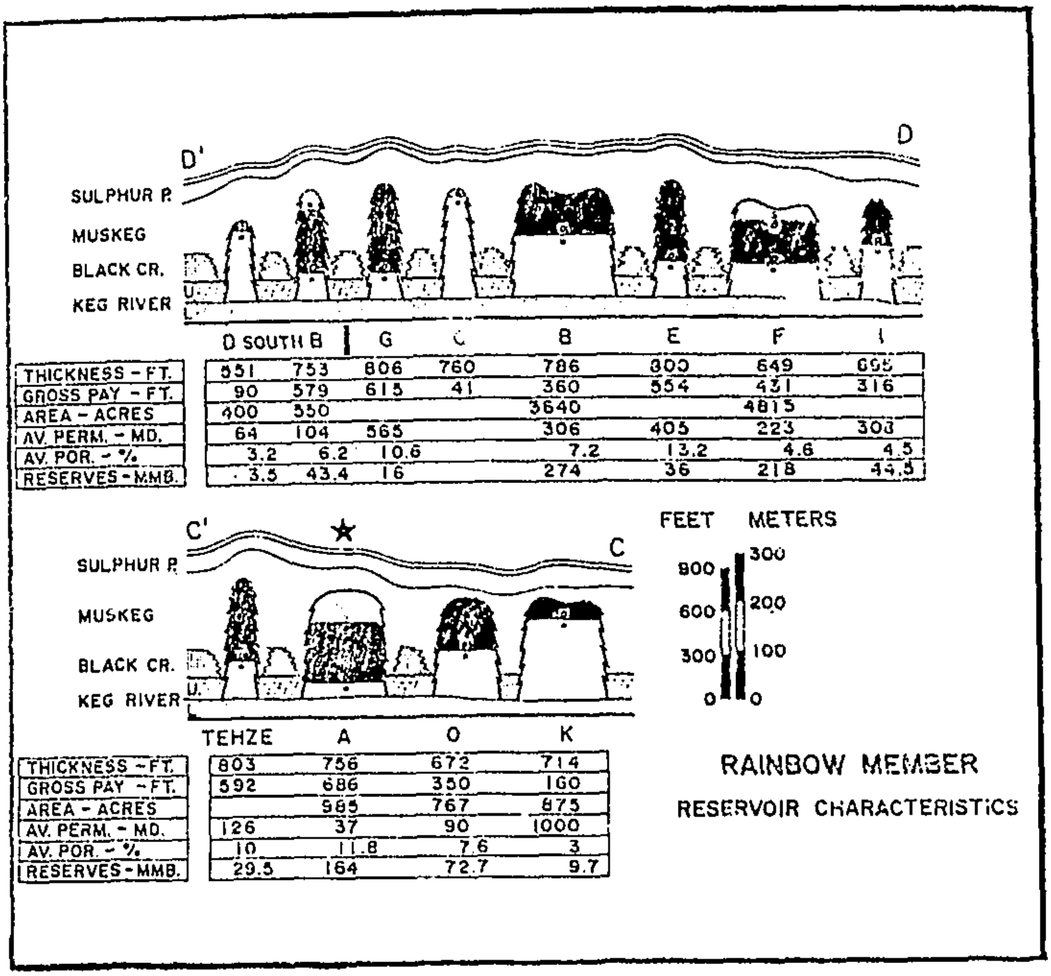


Fig. 4.55 Occurrence of Oil in Reefs, Rainbow Oil Field (Devonian)



	D	SOUTH B	G	C	B	E	F	I
THICKNESS - FT.	551	753	806	760	786	800	649	695
GROSS PAY - FT.	90	579	615	41	360	554	431	316
AREA - ACRES	400	550			3640		4815	
AV. PERM. - MD.	64	104	565		306	405	223	303
AV. POR. - %	3.2	6.2	10.6		7.2	13.2	4.6	4.5
RESERVES - MMB.	3.5	43.4	16		274	36	218	44.5

	TEHZE	A	O	K
THICKNESS - FT.	803	756	672	714
GROSS PAY - FT.	592	686	350	160
AREA - ACRES		965	767	875
AV. PERM. - MD.	126	37	90	1000
AV. POR. - %	10	11.8	7.6	3
RESERVES - MMB.	29.5	164	72.7	9.7

4.3.3.2 Physical Properties of Rocks

Physical properties of rocks are examined from various angles in order to study properties and conditions inherent in rocks and also to specify their secondary deformations. Of these revelant to oil exploration are magnetism, density, threshold pressure, seismic wave velocity, rock strength, etc.

(i) Magnetism

Magnetism of rocks is due mainly to the following two causes, that is, induction magnetization and natural remanent magnetization. In the former case, the strength and direction of magnetization are determined by the magnetic susceptibility of rocks and the value of the earth's magnetic field that is applied externally to them, while in the latter case, the magnetism was caused at the time of the formation of rocks and is inherent in them, and neither the direction nor strength of the magnetization has anything to do with the earth's present magnetic field.

The magnetic susceptibility of a rock is determined by the kinds of magnetic minerals and their contents. The measured value of magnetic susceptibility is clearly proportionate to the content of magnesite, a magnetic substance. Generally speaking, basic igneous rocks (basalt and others), which has a relatively high content of magnetic minerals, are high in magnetic susceptibility, while acidic igneous rocks (granite and others) has a low magnetic susceptibility. The magnetic susceptibility of sedimentary rocks differs according to different source rocks, but it is normally lower than that of igneous rocks (Table 4.31).

Table 4.31 Magnetic susceptibility of Main Rocks (Unit: emu/cc x 10^{-5})

（単位：emu/cc×10^{-5}）

Igneous rocks	Basalt	90～250
	Andesite	60～250
	Rhyolite	1～ 10
	Granite	1～ 10
Sedimentary rocks	Conglomerate	5～100
	Sandstone	5～ 10
	Mudstone	5～ 8

On the other hand, the magnetism of rocks due to natural remanent magnetization* cannot be determined by the content of magnetic minerals alone, as natural remanent magnetization is influenced by the generating mechanism of rocks, such as heat, sedimentation and chemical change. However, excepting certain cases (isothermal remanent magnetization due to thunderbolts, etc.), natural remanent magnetism tends to maintain the direction of the earth's magnetism at the time of origination of rocks. Consequently, the magnetism of rocks may be utilized for estimating the age of their origin or for correlation of strata.

Further, it may be utilized in combination with magnetic susceptibility to classify rocks or to estimate the volume of volcanic rocks.

4.3.3.3 Clay Minerals, Heavy Minerals, and Others

(1) Clay and clay minerals

Clay is a plastic earth-like conglomerate of small particles, a naturally formed object whose chemical components are mainly silicon, aluminum and water mainly and small quantities of iron, magnesium, alkali metals and alkali earth metals. In case the term "clay" is used to express grain size, it is defined as follows:

Wentworth (1922)	1/256mm (≒ 4μ) or less
International Society of Soil Science (1927)	0.002mm (= 2μ) or less
Soil Engineering Society (JIS) (1960)	0.005mm (= 5μ) or less

Minerals (including noncrystal substances, for convenience' sake) which are found in clay as the most important state of occurrence are called clay minerals.

Clay minerals are secondary minerals produced by the disintegration of rock-forming minerals which are alumino-silicates. They have a layered lattice structure and are chemically the most stable minerals under the temperature and pressure conditions near the earth's surface.

The average grain size of clay minerals is very small and is normally 5μ or less. The wholeness of crystals or crystallinity lowers in proportion to grain size, and there is probably no line of demarcation that can be drawn between clay minerals with a low crystallinity and amorphous substances which may be regarded as alumino-silicate gels.

Note: *By "remanent magnetism"is meant the strength of magnetization where the magnetic field acting on a magnetic substance is taken at 0.

(2) Study of a clay minerals

1 Separation of clay minerals

The first step in a study of clay minerals is to separate clay minerals from clay. Clay minerals are separated from non-clay substances in principle by utilizing their grain size differences, but it is often very difficult to separate completely two or more clay minerals respectively from a conglomerate of clay minerals.

The procedure for separating clay minerals is shown in Table 4.33. In the step of hydraulic classification, clay minerals are sorted according to Stokes' rule concerning the relationship between grain size and sedimentation rate. Thus, if clay particles are left suspended in water, the grain size of the particles, which remain suspended between the water surface and a depth of 10cm from it at eight hours after the start of suspension, is 2μ or less in case the water temperature is 20°C.

In analyzing clay for clay minerals, normally clay particles with a grain size of 2μ are used.

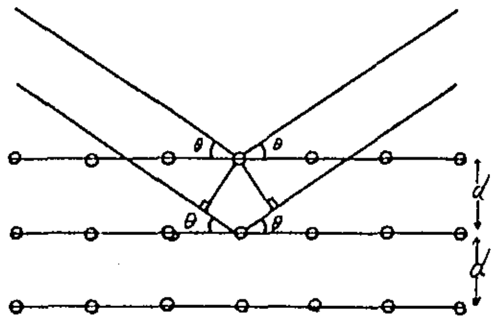
2 X-ray analysis

X-ray diffraction is most effectively used in the study of crystal structures of clay minerals.

X-rays are electromagnetic waves with wavelengths ranging from 0.01 to 1.00Å, and consist of line spectra (characteristic X-rays) which are dependent on the elements used for the anticathode, and continuous spectra (continuous X-rays) which are independent of the elements used. Generally, the former are used in X-ray diffraction, particularly the $K\alpha$ ray of the K series.

When radiated on a crystal, X-rays are reflected from the many lattice faces of the crystal. If the spacing between three-dimensionally arranged crystal lattice faces of an atom is denoted by d, and the angle of incidence of X-rays by – , then the light path difference (2d $\sin\theta$) is required to be an integral multiple of the X-ray wavelength λ (Fig. 4.56) in order that refraction may be caused. Consequently, if the angle of diffraction is measured with the use of an X-ray with a known wavelength, it is possible to identify the mineral by calculating the spacing between crystal faces.

Fig. 4.56 X-ray Reflection on Crystal Lattice Faces Bragg's Equation



$$2d \sin\theta = n\lambda$$

$$(n = 1.2.3 \cdots n)$$

An X-ray diffraction device consists of (1) an X-ray controller, (b) X-ray tube, (3) goniometer (Fig. 4.57), and (4) a counting and recording device.

The qualitative identification of clay minerals is possible by comparing an X-ray diffraction pattern of an unknown sample with that of a known mineral. As most clay minerals have layered structures, there is a similarity in their X-ray diffraction patterns.

An X-ray diffraction pattern contains reflections from the bottom, (060) reflections, reflections from the pyramidal faces, and their secondary and higher order reflections.

a Relections from the bottom are those from the crystal lattice faces perpendicu-

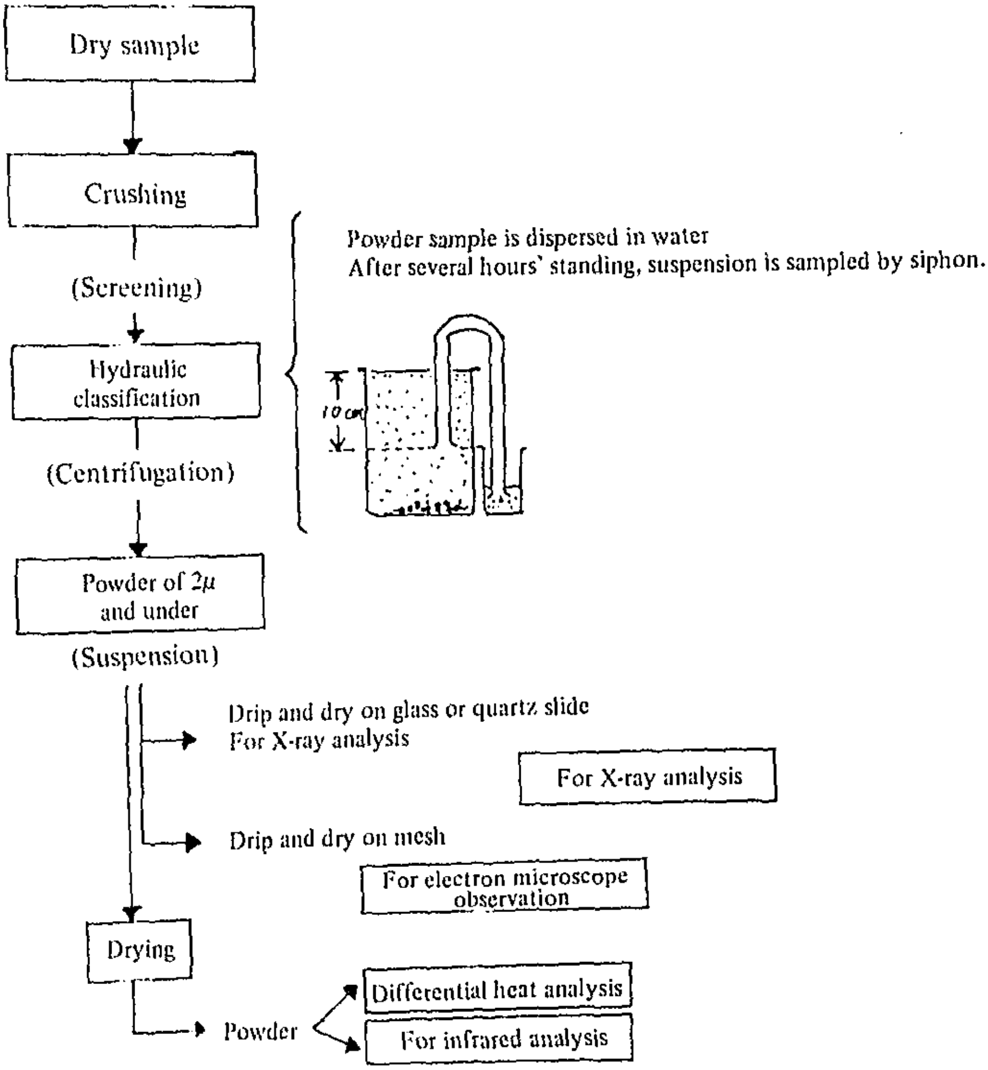
perpendicular to the c axis of a crystal and are important to the identification of clay minerals.

b (060) reflections are from the crystal lattice surfaces vertical to the b axis. These reflections make it possible to classify three-layered structures into 2-octahedral and 3-octahedral layers.

c Reflections from the pyramidal face are from a crystal lattice face which intersects either the a axis or the b axis and which also intersects the c axis, and make it possible to obtain information on how lattices are layered.

Further, samples are treated in various ways for X-ray analysis in order to detect delicate differences or to confirm identifications.

Table 4.33 Procedure for Separating Clay Minerals



Powder sample is dispersed in water
After several hours' standing, suspension is sampled by siphon.

Fig. 4.57 Principle of Goniometer

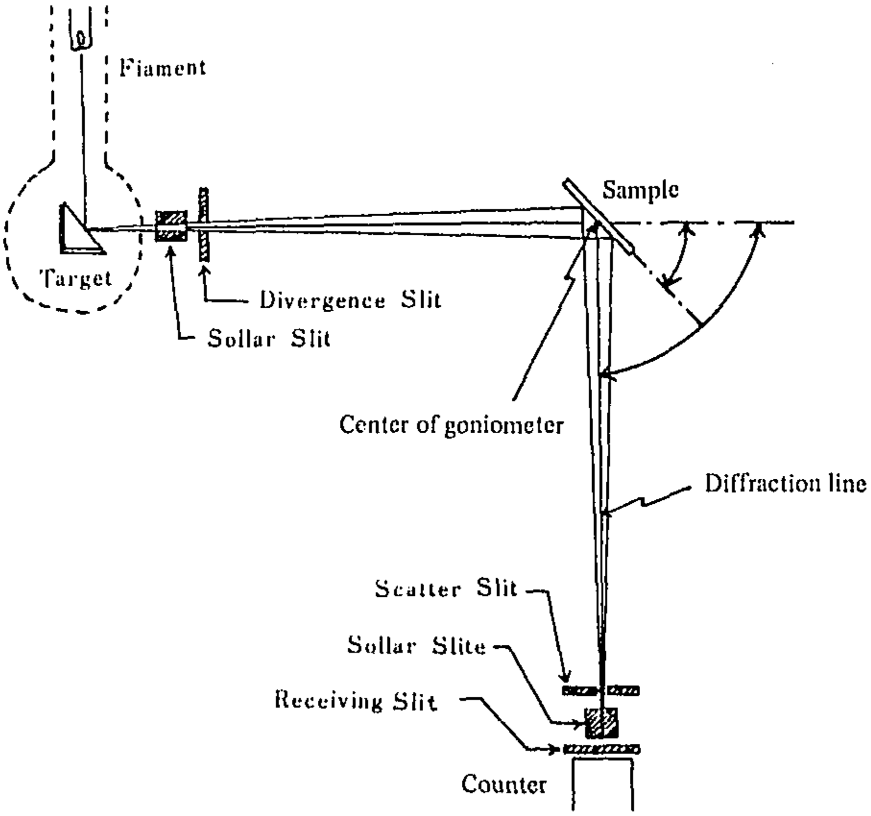
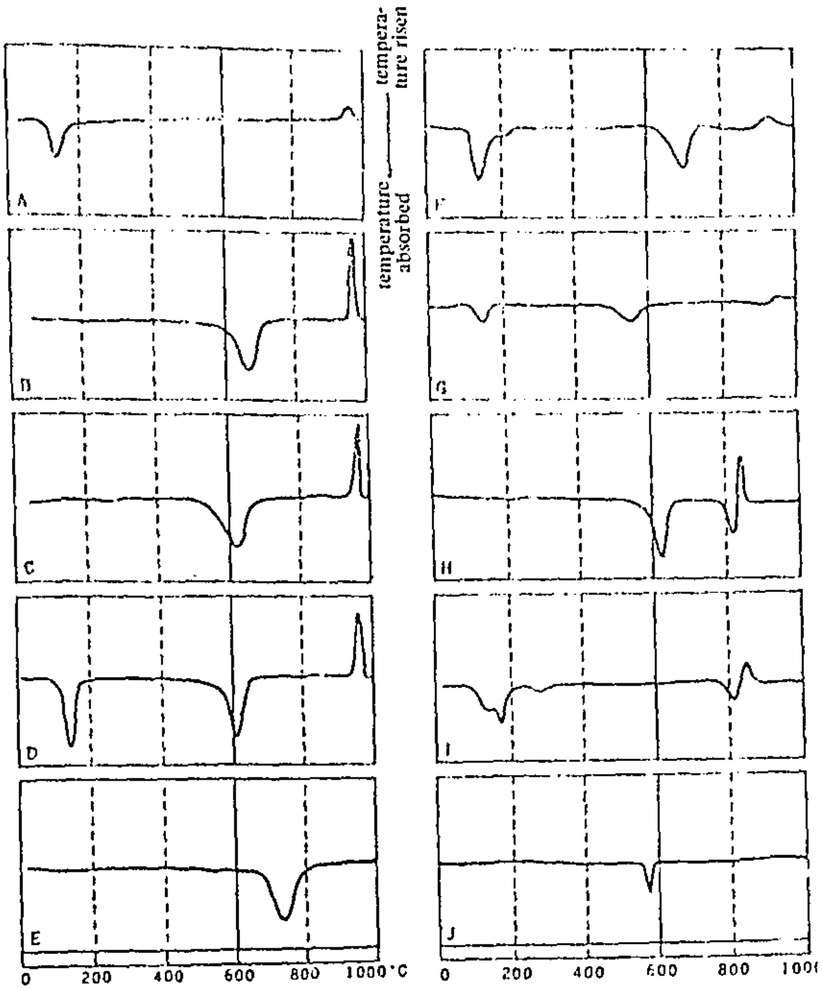


Table 4.34 Major Clay Minerals and Changes Noted After Various Treatments of Principal Bottom Reflections

Bottom reflection (room temperature)		Heat change	Ethylene glycol treatment	Ammonium nitrate treatment
Montmorillonite	15.4 (A°)	→ 9.4 (500°)	→ 17 (A°)	No reaction
Vermiculite	14, 7	→ 9.3 (500°)	No reaction	→ 10 (A°)
		→ Disappears at 300°C		No reaction
Chlorite	14.3, 7	→ 14 (800°)	No reaction	No reaction
		→ Disappears at 700°C		No reaction
Illite	10	→ Disappears at 800°C	No reaction	No reaction
Hydrated halloysite	10	→ 7.2 (400°C)	→ 71	No reaction
Halloysite	7.2	→ Disappears at 600°C	No reaction	No reaction
Kaolinite	7.15	→ Disappears at 600°C	No reaction	No reaction

Fig. 4.58 Differential Heat Analysis Curves for Major Clay Minerals



A : Allophane
B : Dickite
C : Koalinite
D : Halloysite
E : Pyrophyllite
F : Montmorillonite
G : Illite
H : Magnesium vermiculite
J : Quartz

Fig. 4.59 Differential Thermal Analyzer

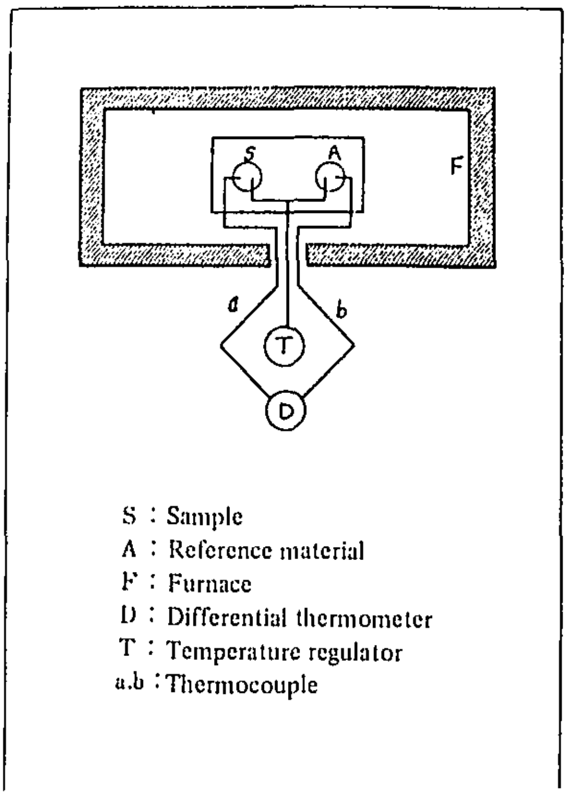


Fig. 4.60 Principle of Electron Microscope

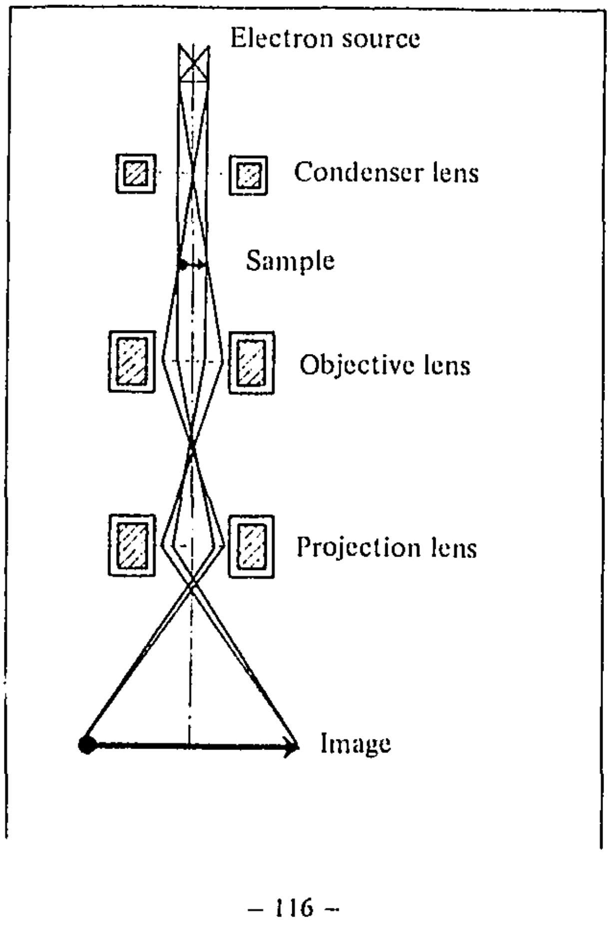


Table 4.35 Forms of Clay Minerals Under Electron Microscope

	Hexagon, imperfect hexagon	Slat-like, fibrous, rod-like	Tubular (probably hollow)	Amorphous	Spherical
Kaolin minerals	Part of kaolinites Dickite	Part of kaolinites	Hydrated halloysite Halloysite	Part of kaolinites	
Montmorillonite minerals		Nontronite Saponite Hectorite		Montmorillonite	
Mica minerals	Part of sericite	Part of sericite		Illite Part of sericite	
Other		α-Sepiolite Attapulgite	Chrysotile	Pyropyllite β-Sepiolite	Allophane

Fig. 4.61 Principle of Infrared Spectrometer

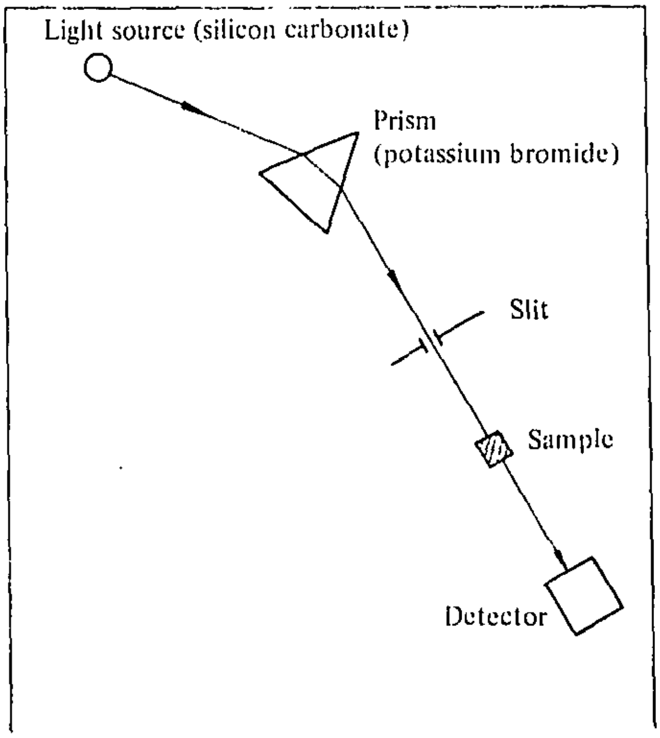
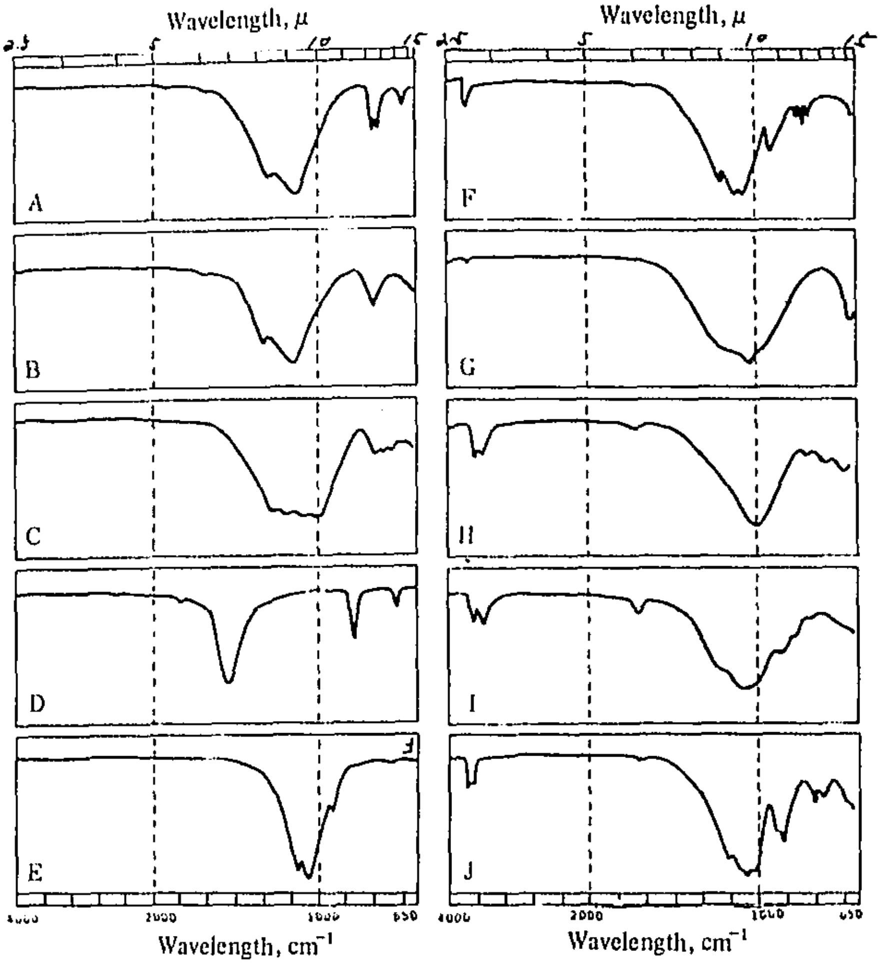


Fig. 4.62 Infrared Absorption Spectra of Major Minerals



A : Quartz
B : Cristobalite
C : Albite
D : Calcite
E : Apatite

F : Pyropyllite
G : Talc
H : Chlorite
I : Montmorillonite
J : Kaolinite

(i) Heat treatment

Structural changes which occur in minerals when they are heated at a certain temperature for a certain duration of time differ in degree and form according to different minerals, and can be effectively used for the purpose of identification.

A film of a sample is made on a piece of quartz glass. It is then heated in an electric furnace, cooled at room temperature, and X-ray-analyzed immediately.

(ii) Ethylene glycol treatment

Ethylene glycol penetrates into the space between the lattices of montmorillonite a and other clays and bonds with them because of its strong affinity for them. As a result, the distance between layers changes remarkably. As montmorillonite is very sensitive to it, it is possible to detect montmorillonite, however small the quantity of montmorillonite contained in a sample.

(iii) Others

In case samples are treated with hydrochloric acid, ammonium nitrate or other chemicals, they are boiled in the form of powder in the reagent.

Table 4.34 shows changes that occur in reflections from the main bottoms of important clay minerals after they are treated in various ways.

3 Differential thermal analysis

Thermal analysis is a method of characterizing changes that occur in the properties of minerals due to temperature changes. Of the various methods of thermal analysis, differential thermal analysis is the most effective in the study of clay minerals.

According to this method, a sample and a standard sample (α-alumina and other thermally inactive substances) are heated in an electric furnace at a certain rate of temperature increase, and the temperature differences between the two samples are measured.

In case a loss or gain of heat occurs in the sample, a temperature difference between the sample and the standard sample is generated. The temperature rise rates of some samples are higher and those of other samples lower than the rate for the standard sample. The former cases involve exothermic reaction and the latter cases endothermic reaction.

Clay minerals are generally stable at lower temperatures and thus the different phases formed by heating are treated as independent mineral species. These phase changes are observed in cases where dehydration takes place (heat absorption), a dehydrate is transformed to a more stable phase (heat generation), and in other cases, and the quantity and state of change in energy can be shown in curves in relative terms. These changes are controlled by the chemical components, crystal structure, grain size and other properties of clay minerals.

Fig. 4.58 shows the curves of differential thermal analysis of major clay minerals, and Fig. 4.59 the principle of a differential thermal analyzer.

4 Electron microscope

In many cases, small crystals of clay minerals are beyond the resolving capacity of optical microscopes. Therefore, an electron microscope with a high resolution (1–20Å) and a high magnifying power (300 – 300,000 magnifications) is an effective means for morphological observations.

The principle of the electron microscopes is illustrated in Fig. 4.60.

A sample for electron microscope observation is prepared by dropping the suspended sample on meshed supporting film, and by shadowing it after drying.

Morphological characteristics of clay minerals as observed under an electron microscope are shown in Table 4.35.

Further, it is possible to obtain diffraction patterns of single crystals by means of electon beams (electron beam diffraction).

5 Infrared absorption spectrum

Oscillation of atoms in a molecule includes a number of basic vibrations. Among them, those vibrations in which there is a change in the dipole moment of the molecule are called "infrared-active." In case infrared rays are radiated on the molecule, infrared rays with the frequency as the molecule are absorbed.

In an ordinary analysis, a light source emitting a continuous spectrum in the infrared range is used to obtain a spectrum form which infrared rays with the same frequency as the natural frequency of the sample placed in the light path are absorbed (Fig. 4.61).

This method is mineralogically effective for research into the following: (a) Changes in the composition of clay minerals in case chemical compositions are wide-ranged, and (b) polymorphisms, and (c) kinds of water in minerals.

The infrared absorption spectra of major minerals are shown in Fig. 4.62.

The absorption spectra of clay minerals show different absorption bands mainly according to the conditions of water contained in them.

In addition to the above, there are chemical analysis procedures and colloid-chemical methods for the study of clay minerals, but discussion of these methods is omitted here.

(3) Crystal structure of clay minerals

Similarities and differences between clay minerals are due to their crystal structures. The crystal structures of clay minerals basically consist of the following two structural units.

1. SiO tetrahedral layers formed by SiO_4 groups each sharing its three hydrogen atoms with its adjoining groups
2. An octahedral layer composed of most densely packed two-layered hydroxy radical or oxygen and bivalent or trivalent metal element ions (e.g. aluminum).

These two structural units are bonded by sharing an oxygen atom in the tetrahedral layer.

Each clay mineral differs from others in the relative numbers of these two structural units and in the possibility of silicon and aluminum being replaced by other elements.

A structure, as represented by kaolinite, consists of a tetrahedral layer and an octahedral layer is called the two-layered structure (1 : 1 type structure).

A structure, which, as represented by montmorillonite, an octahedral layer sandwiched between two tetrahedral layers is called the three-layered structure (2 : 1 type structure).

Of the clay minerals with a three-layered structure, those minerals in which all the six-coordination lattice points where the metal elements are positioned in the hexahedral layer are occupied by bivalent metal element ions (magnesium, ferrous ion, etc.) are called minerals of a three-octahedral three-layered structure. Further, in case trivalent metal element ions (aluminum, etc.) are positioned at the six-coordination lattice points, only two-thirds of lattice points are occupied by bivalent metal element ions so that the entire electric charge may be neutralized, and the remaining one-third are vacant. Such minerals are called minerals of a two-octahedral three-layered structure.

The crystal structures of major clay minerals are shown in Fig. 4.63.

(4) Major clay minerals

1 Kaolinite

Its chemical formula is $Al_2Si_2O_5(OH)_4$. Kaolinite is one of the four polymorphisms, the three others being nacrite, deccaite, and halloycite.

Generally speaking, kaolinite occurs in sedimentary rocks and soil as hydrothermally alterated minerals of volcanic rocks or as weathering products of mica, fledspar and volcanic glass fragments.

2 Montmorillonite

Its general chemical formula is as follows:

$(X, Y)_{2-3}Z_4O_{10}\ (OH)_2 \cdot mH_2O \cdot W_w$

X = Al, Fe^{3+}, Mn^{3+}, Cr^{3+}
Y = Mg, Fe^{2+}, Mn^{2+}, Ni, Zn, Li
Z = Si, Al
W = K, Na, Ca (Easily replaceable)

It has a complex chemical constitution, as a great number of ions are contained by isomorphous substitution.

Montmorillonite is characterized by a great cation exchangeability and by characteristic swelling.

Generally, it occurs as hydrothermal alterations of felsitic volcanic rocks and tuff or as a product of their weathering.

Bentonite is a kind of clay containing montmorillonite as its main component mineral and and is used as an adjusting agent for drilling sludging.

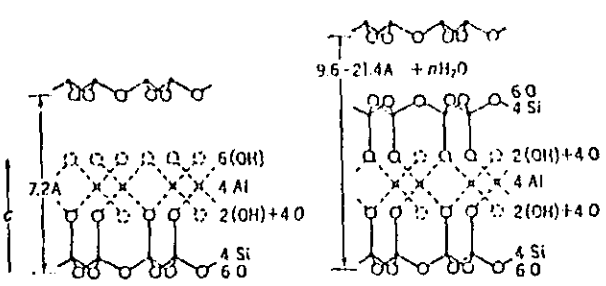
3 Chlorite

Structurally, chlorite has two separate octahedral layers, one in the three-layered latt and the other between the adjoining three-layered lattices.

Chlorite is a solid solution with a serpentite molecule [$Mg_{12}Si_8O_{20}(OH)_{16}$] and an amesite molecule [$(Mg_8Al_4)(Si_4Al_4)O_{20}(OH)_{16}$] as its end components and Si in the tetrahedral layer is replaced by Al or Fe^{3+}, and the resulting shortage of positive electric charge is compensated for by the substitution of Al^{3+} for Mg^{2+} in the hexahedral layer.

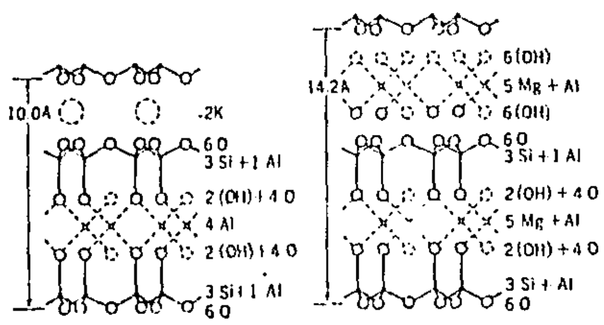
Generally, chlorite is classified into the following two kinds.

Fig. 4.63 Structural Diagrams of Major Clay Minerals



Kaolinite
$Al_4Si_4O_{10}(OH)_8$

Montmorillonite
$Al_4(Si_4O_{10})_2(OH)_4 \cdot xH_2O$



Muscovite
$K_2Al_4(Si_6Al_2)O_{20}(OH)_4$

Chlorite
$Mg_{10}Al_2(Si_6Al_2)O_{20}(OH)_{16}$

Orthochlorite	$(Mg_{6-x}\ Al_x)\ (Si_{4-x}Al_x)\cdot O_{10}\ (OH)_8$
Leptochlorite	$[(Mg, Fe)_{6-x}Al_{x+2/3y}]\cdot(Si_{4-x}Al_x)O_{10}(OH)_8$

A larger part of chlorite belongs to the former, and chlorite with a high Fe content belongs to the latter.

It occurs in low metamorphic rocks, sedimentary rocks and hydrothermally alterated igneous rocks.

4 Vermiculite

Vermiculite has a water layer ($4H_2O$) instead of an octahedral layer that chlorite has between the adjoining three-layered lattices. Its chemical formula is $(Mg, Fe)_3(Al, Si)_4\ O_{10}(OH)_2 4H_2O$.

5 Mica clay minerals

White mica has potassium between montmorillonite's adjoining three-layered structures. Generally speaking, the chemical formula of mica type clay minerals is as follows.

$W_x(X, Y)_y\ Z_4O_{10}(OH)_2$
W = K (small quantities of Na, Ca)
X, Y = Al, Fe^{3+} (small quantities of Mg, Fe^{2+})

Among mica type clay minerals, those whose main component is aluminum are illite and phlogopite, and others whose main component is Fe are celadonite and glauconite.

6 Pyrophyllite

The chemical formula of pyrophyllite is $Al_4\ (Si_8O_{20})\ (OH)_4$. It occurs as an alterated mineral of feldspar in hydrothermal minerals. It is a main constituent mineral of pyrophyllite.

7 Mixed layer clay minerals

"Mixed layer clay minerals" refer to those clay minerals whose layers are piled one upon another in parallel layers. In some mixed layer clay minerals, layers are piled one upon another in a completely irregular order (the completely irregular type) while in others, component layers are piled one upon the other alternately (the completely regular type).

Mixed layer minerals wtih the following combinations are known.

Chlorite	Montmorillonite
Illite	Montmorillonite
Chlorite	Vermiculite, etc.

Clay minerals are classified in Table 4.36.

Table 4.36 Classification of Clay Minerals

Type	Group	Sub Group	Species Alluminum type	Species Magnesium type	Species Iron type
2 : 1	Pyrophyllite	Pyrophyllite	Pyrophyllite		
	Talc			Talc	
	Montmorillonite	2-Octahedron montmorillonite	Montmorillonite		Nontronite
	Saponite	3-Octahedron montmorillonite	Beidellite	Saponite	
	Vermiculite	2-Octahedron vermiculite		Hectorite	
		3-Octahedron vermiculite	2-Octahedron vermiculite		
			3-Octahedron vermiculite		
		2-Octahedron mica	Sericite		Celadonite
	Mica	3-Octahedron mica	Illite	Phlogopite	Glauconite
	Friable mica	2-Octahedron friable mica	Margarite		
		3-Octahedron friable mica		Xanthophyllite	
2:1:1	Chlorite	2-Octahedron chlorite	Sudoite		
		3-Octahedron chlorite	Pennine, Clinochlore, Prochlorite		
1 : 1	Kaolinite	Kaolinite	Kaolinite		
	Serpentinite	Serpentinite	Halloysite		
				Chrysotile	
				Antigorite	

(5) Formation of clay minerals

1 Volcanic hydrothermal action

2 Erosion

In either case, the interaction between the source rock and media in contact with it is an important factor, and the kinds of clay minerals produced are dependent on temperature, pressure,pH of the media, the velocity of the media, and the chemical composition of the source rock.

In hydrothermal action, the kinds of minerals formed depend on the nature of the solution. Thus, sericite, chlorite and montmorillonite are formed in neutral and weakly alkali environments, and kaolinite, deccaite and pyrophyllite in weakly acid environments.

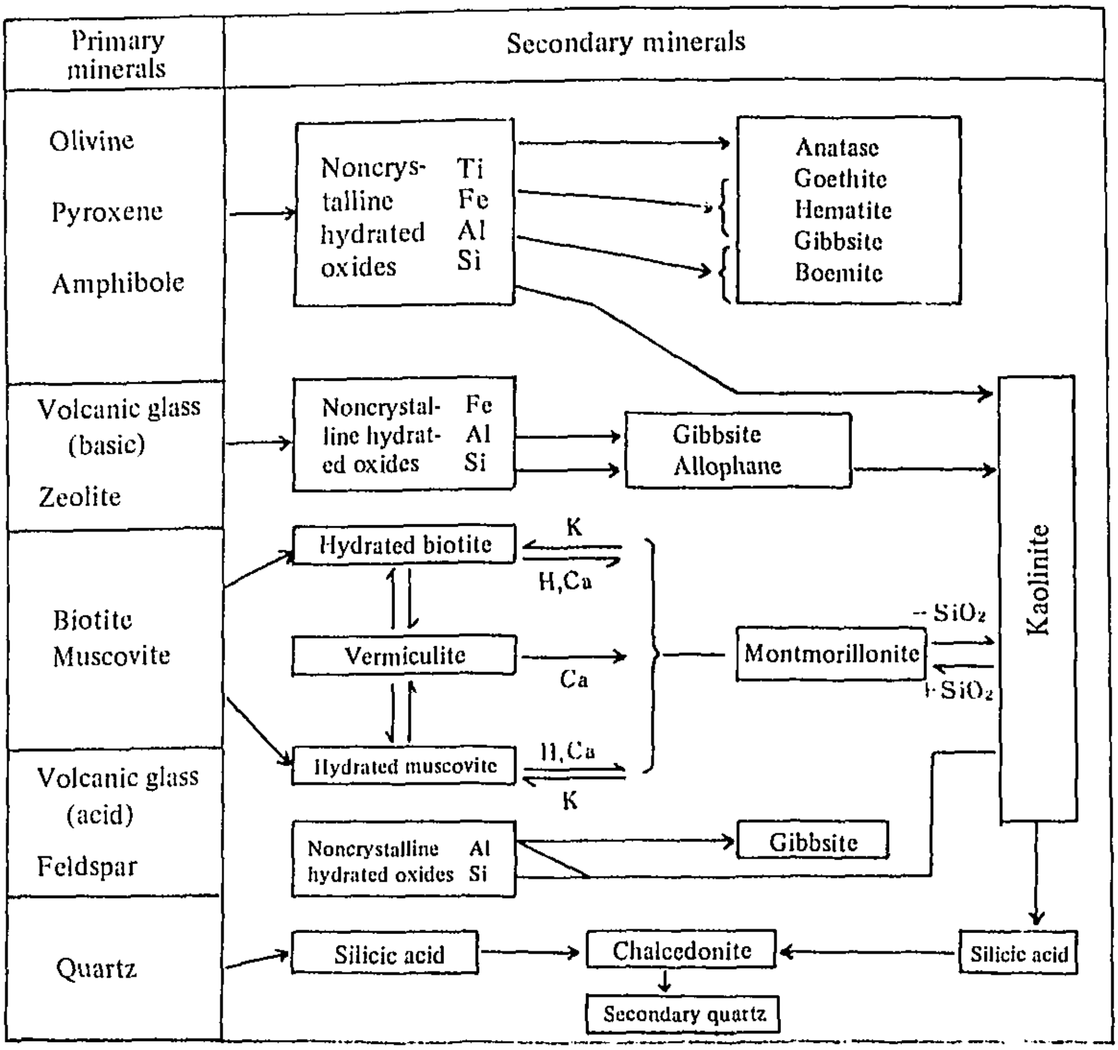
Formation of clay minerals due to weathering is influenced by climatic, topographical and biological conditions, as well as by the chemical composition of the source rock. Table 4.37 shows the weathering process of rock-forming minerals.

Clay minerals in sedimentary rocks formed by weathering sensitively reflect the sedimentation environment. Relationships between clay minerals in sedimentary rocks and sedimentation environment may be summed up as follows.

a Illite always constitutes the main component of marine formations, showing that it is an ultimate, stable product of long exposure to sea water. Sometimes, it si accompanied by small quantities of chlorite and hydrate mica, but as a general rule, kaolinite does not occur.

b Kaolinite is the main component of fresh water lake formations, but in a calcareous environment, illite is the main component, with small quantities of chlorite and montmorillonite.

Table 4.37 Weathering of Primary Rock-forming Minerals



c Illite is the main component of recent marine formations, with small quantities of montmorillonite, kaolinite and chlorite. Occasionally, however, relatively large quantities of montmorillonite and kaolinite are found.

d Generally speaking, montmorillonite and kaolinite are found in smaller quantities in old sedimentary rocks than in new ones, while illite is found in larger quantities in old sedimentary rocks. This is believed due to the fact that montmorillonite and kaolinite become unstable by diagenesis and are turned into illite. Further, this shows that illite is the most stable, ultimate product in cases where ordinary sedimentary rocks are subjected to diagenesis.

e Kaolinite is found more in some coal-bearing formations, and illite in others. In calcareous formations, however, illite is always dominant, sometimes mixed with montmorillonite.

Table 4.38 sums up various causes of formation of clay minerals.

Table 4.38 Formation Processes of Various Clay Minerals

Hydrothermal	Land weathering	Benthic weathering	Submarine volcanic action
Pyrophyllite Chlorite Kaolinite Dickite Nacrite Celadonite Sericite Montmorillonite Talc	Kaolinite Halloysite Hydrated halloysite Allophane Illite Montmorillonite	Chlorite Celadonite Illite Montmorillonite Glauconite	Celadonite

(6) Heavy minerals

"Heavy minerals" mean those minerals which are contained in sandy sediments as source rock residues remaining after erosion and disintegration, and whose specific gravity is 2.85 or more. Main heavy minerals are listed in Table 4.39.

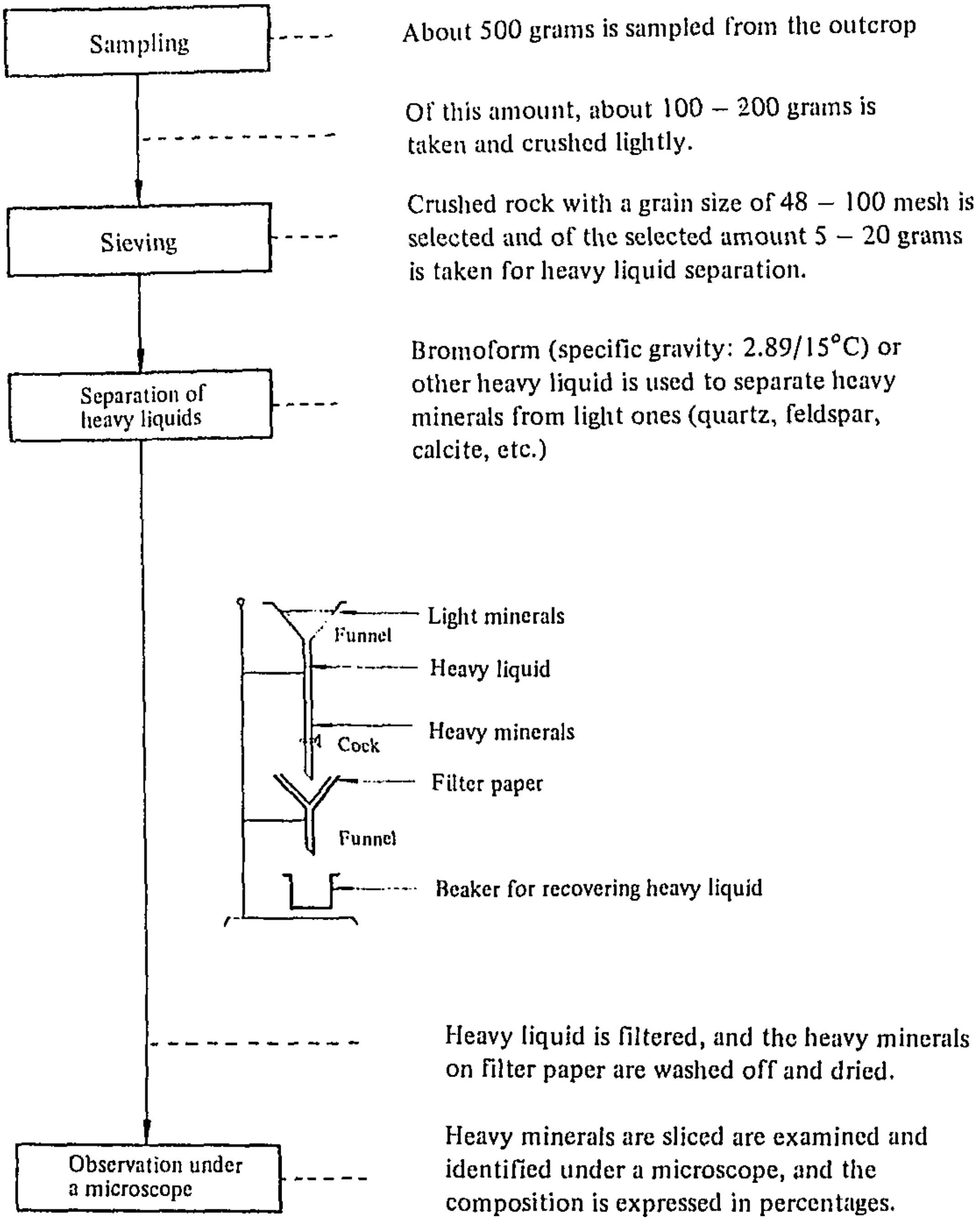
Table 4.39 Classification of Heavy Minerals

Classification	Main heavy minerals	Remarks
Opaques	Magnetites (hematite, limonite) Titanite (leucoxene)	○Alterated minerals (in parentheses at left) occur as heavy minerals in sedimentary rocks. ○Both resist oxidation, and readily soluble. ○Magnetite and titanite sometimes occurs as authigenic minerals.
Ultrastables	Zircon Tourmaline Rutile	○These are important as they are very hard and resist chemical action. ○Sedimentary rocks in which these are overwhelmingly dominant and other minerals are lacking indicate that they were subjected to weathering for a long period of time. ○These minerals also occur as authigenic minerals.
Metastables	Olivine Epidote Garnet Apatite Kyanite Andalusite Staurolite Amphibole Hypersthene Augite	○These minerals, which are somewhat vulnerable to chemical change, occur in largest quantities and are important in detailed analysis of the process of formation of sedimentary rocks. ○Most of these heavy minerals derive from various kinds of igneous rocks and metamorphic rocks.

Normally, heavy minerals contained in sediments are less than 1% (by weight).

The combinations of heavy minerals and of their quantities or their compositions are investigated by the procedure described in Fig. 4.64. In this way, clues are provided for the following information:

Fig. 4.64 Procedure for Analysis of Heavy Minerals



About 500 grams is sampled from the outcrop

Of this amount, about 100 – 200 grams is taken and crushed lightly.

Crushed rock with a grain size of 48 – 100 mesh is selected and of the selected amount 5 – 20 grams is taken for heavy liquid separation.

Bromoform (specific gravity: 2.89/15°C) or other heavy liquid is used to separate heavy minerals from light ones (quartz, feldspar, calcite, etc.)

Heavy liquid is filtered, and the heavy minerals on filter paper are washed off and dried.

Heavy minerals are sliced are examined and identified under a microscope, and the composition is expressed in percentages.

1 The source rock can be determined on the basis of the kinds of heavy minerals contained.

2 Identification and correlation of strata can be carried out by utilizing the fact that a composition of heavy minerals often represents stratification characteristics.

3 Paleogeographical and paleogeological maps can be reconstructed by zoning the layers of each geological age in a certain area according to the compositions of heavy minerals and by analyzing the occurrence of heavy minerals, changes in their quantities and their loss.

Generally speaking, the analysis of heavy minerals serves an important purpose, as it can be combined with other methods (for instance, research into paleostream systems) to obtain information on sedimentary environments, paleogeography or generally on matters related to the earth's history.

4.4 Overall Geological Interpretation and Evaluation

Sometimes, the possibility of the existence of oil field formations is studied on the basis of an overall geological interpretation; at other times, oil reservoirs are directly evaluated on the basis of an overall geological interpretation through test-drilling. The result of the latter is fed back to the former study, and the possibility of the existence of oil field formations in a broader area is examined. This can lead to test drilling and its evaluation. As data are accumulated in this way, evaluations change from time to time.

Various investigations by test drilling - - including many kinds of DST (including FT and MFE) and oil production tests, in addition to the above-mentioned geological, geochemical and lithological researches - - are aimed at evaluating oil reservoirs and estimating the mineable reserves and the productivity of oil wells. We will omit discussing these matters, which are dealt with in a separate section titled "Oil Well Research," and study the possibility of the existence of oil field formations on the basis of various kinds of comprehensive geological information derived from data on existing oil wells and also from other geological data.

As explained above, there are a number of basic conditions for the formation of oil fields, and in many cases it is extremely difficult to obtain data which sufficiently satisfly all these conditions.

The following maps are required to select necessary data from countless data for the purpose of an overall interpretation.

4.4.1 Geological Maps

These are the most basic maps, and those maps drawn on scales of 1:5,000 to 1:5,000,000 are available and used for different purposes. Most frequently used are those on scales of 1:50,000 to 1:200,000.

In many cases, comprehensive geological maps incorporate iso-gravity lines, seismic prospecting maps, maps showing the underground structures of oil fields, and those showing the position of oil wells.

Tectonic maps are a simplified means of showing geological structures and are used in investigating complex configurations and structures.

4.4.2 Geological Sections

These are ordinary geological maps containing cross sectional lines and diagrams. They illustrate not only the surface geology but also lithofacies and changes in formation thicknesses by fully utilizing well data and seismic prospecting cross-sections and gravity cross-sections. It is desirable that geological sections, together with such supplementary information, will give necessary information on the structural cross-sections of sedimentary basins at a glance. Since geological sections are based on correct stratigraphic data and lithofacies, they can be reliable only when data of fossil organisms, heavy minerals, electrical well-logging, and paleomagnetism are fully utilized for the purpose of correlation. In addition to stratigraphy, recently the K-Av method and the fission tracking method which utilizes the spontaneous nuclear fission of uranium have come to be applied for the purpose of estimating the age of geological formations through measurement of radioactivity. These methods are being applied successfully in the oil-bearing zones of Tohoku (northwestern Japan) facing the Japan Sea.

Stratigraphical sections or restored sections:

Stratigraphical sections or restored sections are maps showing stratigraphic horizons from the bottom upwards, together with the water depths at the time of sedimentation and lithofacies. Developed on a plane, these sections are lithofacies maps, paleogeological, peleogeographical and other maps. These sections are very important and are essential to the study of the formation, migration and accumulation of oil.

4.4.3 Structure Maps or Tectonic Maps

Many structural bathymetric charts can be obtained for the same area with the use of different bedding planes or markers.

Such charts are particularly necessary for the selection of oil fields or test-drilling points. In selecting oil fields, it is desirable that an oil reservoir or a marker as close to the reservoir as possible be selected for the preparation of such charts. These charts will make it possible to recognize structural differences in stratigraphical horizons, and understand the process of structural development with the aid of the above-mentioned restored sections.

Seismic prospecting is most desirable in obtaining information on the configurations of sedimentary and techtonic basins. However, because of the high cost and time required for seismic prospecting, aeromagnetic surveys are sometimes preferred, as these surveys can give general information on these matters. Aeromagnetic basement maps are an example of such surveys. However, serious errors may sometimes be committed depending on input data and methods of analysis. Therefore, utmost care should be taken in interpreting the results of aeromagnetic surveys.

4.4.4 Isopach Maps and Lithofacies Maps

Isopach maps show changes in the thicknesses of specific strata and of oil reservoirs and it is desirable that these maps and lithofacies maps be shown on the same plane. Like the above-mentioned geological sections and restored sections, these maps are very important and are essential particular to the discovery of oil reservoirs in carbonate rocks.

There are many kinds of lithofacies maps, which are used for different purposes.

Lithofacies maps showing changes in lithofacies, stratum-by-stratum, in sedimentary basins as if they were geological maps, are widely used. Particularly in Japan, sand:shale:tuff ratio maps, which show ratios of mudstone to sandstone to tuff in different colors, and sand:shale ratio maps find extensive use.

Isopach maps of independent lithofacies and particularly of beds in which gas or oil reservoirs are found are called isolith maps. $CaCo_3$:$CaSO_4$ ratio maps and Ca^{++}:Mg^{++} ratio maps are also drawn for areas rich in carbonate rocks.

4.4.5 Paleogeological Maps and Paleogeographical Maps

Geological maps of formations under the surfaces of unconformity strata are usually called paleogeological maps, and a highly sophisticated technique is required to draw such maps.

Paleogeographical maps show the distribution of land and sea and sea depths at a given time. Usually, these maps show the seabed environment of a certain formation in the early and last stages of sedimentation according to paleobiological data and changes in lithofacies and strata thicknesses. These maps are called paleoecological maps or paleobathymetric maps. According to percentages of colonies of micropaleoorganisms or classification of colonies, deep stagnant, inner neritic, bathyal, shallow submarine barriers are shown clearly. Sometimes bathymetric charts are made on the assumption that the living environment of the colonies of recent benthic microorganisms is applicable to their past environment.

4.4.6 Other Maps

In addition to the above, there are various kinds of ratio maps, or isocontent maps. For instance, carbon ratio maps and organic carbon or hydrocarbon isocontent maps are used to estimate oil yield potentials, and such maps have been used with reasonable result for the Niigata districts.

It is known that the apparent density of mudstone directly over or under oil or gas reservoirs falls suddenly in special instances. Arguments are divided over whether this indicates the behavior of the cap rock due to abnormally high pressure or it is due to the participation of this zone in the collection of gas or oil. Isoshaledensity maps appear to show that this phenomenon occurs in many cases in structural peaks, but this question still remains to be solved.

As explained above, it is by fully utilizing all the above-mentioned data, repeating corrections and accumulating data for their integration and by obtaining detailed information on the history of historical development of sedimentation and the process of structural development that we can obtain information on the formation, migration and accumulation of hydrocarbons, develop methods of exploration for new areas and increase the probability of discovery of mineral deposits. It is necessary for us to collect more data, broaden our field of vision, and gain a deeper insight into the future.