

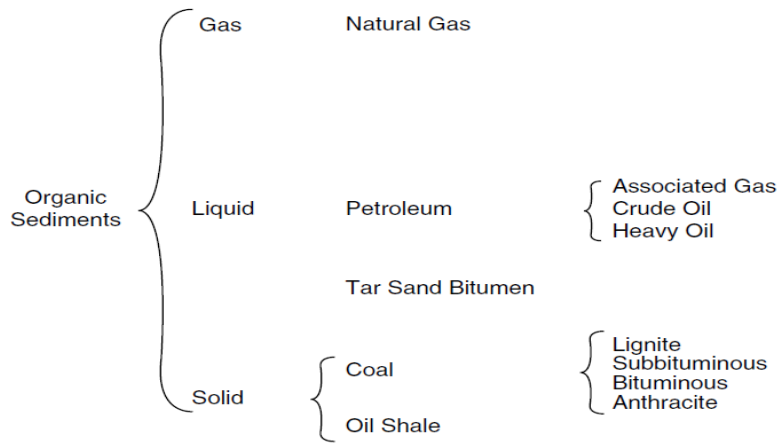
CLASSIFICATION OF CRUDE OIL

CLASSIFICATION SYSTEMS

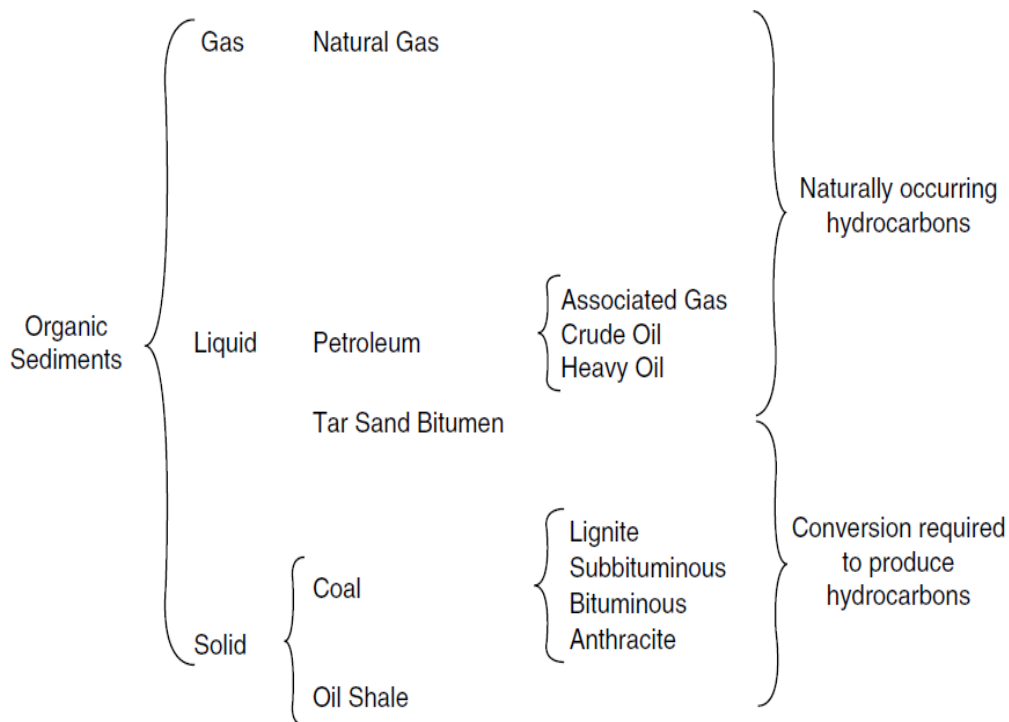
1. CLASSIFICATION AS A HYDROCARBON RESOURCE

Petroleum is referred to generically as a fossil energy resource and is further classified as a hydrocarbon resource and, for illustrative (or comparative) purposes in this text, coal and oil shale kerogen have also been included in this classification. However, the inclusion of coal and oil shale under the broad classification of hydrocarbon resources has required (incorrectly) that the term hydrocarbon be expanded to include the macromolecular nonhydrocarbon heteroatomic species that constitute coal and oil shale kerogen. Use of the term organic sediments would be more correct. The inclusion of coal and oil shale kerogen in the category hydrocarbon resources is due to the fact that these two natural resources (coal and oil shale kerogen) will produce hydrocarbons on high-temperature processing. Therefore, if coal and oil shale kerogen are to be included in the term hydrocarbon resources, it is more appropriate that they be classed as hydrocarbon-producing resources under the general classification of organic sediments.

Thus, fossil energy resources divide into two classes: (1) naturally occurring hydrocarbons (petroleum, natural gas, and natural waxes), and (2) hydrocarbon sources (oil shale and coal) which may be made to generate hydrocarbons by the application of conversion processes. Both classes may aptly be described as organic sediments. Petroleum contains high proportions of individual hydrocarbons (Bestougeff, 1967). The mineral waxes, such as ozocerite, can also be shown on this scheme (Figure 2.2), but because of their character (solid), fall at the lower end of the scale. This should not be construed to mean that the mineral wax is the same heteroatomic material as coal and kerogen but is a result of the physical state.



Subdivision of the earth's organic sediments



Classification of the earth's organic sediments according to hydrocarbon occurrence and Production

In summary, the classification of petroleum and natural gas as naturally occurring mixtures of hydrocarbons occurs by virtue of the fact that they can be separated into their original hydrocarbon constituents that have not been altered by any applied process. The hydrocarbon constituents, separated from petroleum and natural gas, are the hydrocarbon

constituents that existed in the reservoir. Naturally occurring hydrocarbons are major contributors to the composition of petroleum and natural gas. Coal and kerogen do not enjoy this means of separation and methods of thermal decomposition must be applied before hydrocarbons are produced. And these hydrocarbon products, generated by the thermal process, are not naturally occurring hydrocarbons.

Classification By Chemical Composition

Composition refers to the specific mixture of chemical compounds that constitute petroleum. The composition of these materials is related to the nature and mix of the organic material that generated the hydrocarbons. Composition is also subject to the influence of natural processes such as migration (movement of oil from source rock to reservoir rock), biodegradation (alteration by the action of microbes), and water washing (effect of contact with water flowing in the subsurface) upon that composition. Thus, petroleum is the result of the metamorphosis of natural products as a result of chemical and physical changes imparted by the prevailing conditions at a particular locale. The composition of petroleum obtained from the well is variable and depends not only on the original composition of the oil in situ but also on the manner of production and the stage reached in the life of the well or reservoir. In general terms, petroleum (conventional crude oil) ranges from a brownish green to black liquid having a specific gravity (at 60°F, 15.6°C) that varies from about 0.75 to 1.00 (578 to 108 API), with the specific gravity of most crude oils falling in the range 0.80 to 0.95 (45° to 17° API). The boiling range of petroleum varies from about 208°C (688°F) to above 350°C (660°F), above which active decomposition ensues when distillation is attempted. Petroleum can contain from 0% to 35% or more of gasoline, as well as varying proportions of kerosene hydrocarbons and higher boiling constituents up to the viscous and non volatile compounds present in lubricant oil and in asphalt. Thus, petroleum varies in composition from one oil field to another, from one well to another in the same field, and even from one level to another in the same well. This variation can be in both molecular weight and the types of molecules present in petroleum. The hydrocarbons found in petroleum are classified into the following types:

1. Paraffins, i.e., saturated hydrocarbons with straight or branched chains, but without any ring structure

2. Cycloparaffins (naphthenes), i.e., saturated hydrocarbons containing one or more rings, each of which may have one or more paraffin side-chains (more correctly known as alicyclic hydrocarbons)

3. Aromatics, i.e., hydrocarbons containing one or more aromatic nuclei such as benzene, naphthalene, and phenanthrene ring systems that may be linked up with (substituted) naphthalene rings or paraffin side-chains.

CORRELATION INDEX

An early attempt to give the classification system a quantitative basis suggested that a variety of crude should be called asphaltic if the distillation residue contained less than 2% wax. A division according to the chemical composition of the 250°C to 300°C (480°C to 570°F) fraction has also been used, but the difficulty that arises in using such a classification is that in the fractions boiling above 200°C (390°F) the molecules can no longer be placed in one group, because most of them are of a typically mixed nature. Purely naphthene or aromatic molecules occur very seldom; cyclic compounds generally contain paraffin sidechains and often even aromatic and naphthene rings side by side. More direct chemical information is often desirable and can be supplied by means of the correlation index (CI).

Classification by Chemical Composition

Composition of 250°C–300°C (480°F–570°F) Fraction

Paraffin (%)	Naphthene (%)	Aromatic (%)	Wax (%)	Asphalt (%)	Crude Oil Classification
>46, <61	>22, <32	>12, <25	<10	<6	Paraffin
>42, <45	>38, <39	>16, <20	<6	<6	Paraffin–naphthene
>15, <26	>61, <76	>8, <13	0	<6	Naphthene
>27, <35	>36, <47	>26, <33	<1	<10	Paraffin–naphthene–aromatic
<8	>57, <78	>20, <25	<0.5	<20	Aromatic

TABLE 4.14
Classification According to API Gravity

		Fraction		
250°C–270°C (480°F–520°F)		275°C–300°C (525°F–570°F)		
API Gravity	Type	API Gravity	Type	Classification
>40.0	Paraffin	>30.0	Paraffin	Paraffin
>40.0	Paraffin	20.1–29.9	Intermediate	Paraffin–intermediate
33.1–39.9	Intermediate	>30.0	Paraffin	Intermediate–paraffin
33.1–39.9	Intermediate	20.1–29.9	Intermediate	Intermediate
33.1–39.9	Intermediate	<20.0	Naphthene	Intermediate–naphthene
<33.0	Naphthene	20.1–29.9	Intermediate	Naphthene–intermediate
<33.0	Naphthene	<20.0	Naphthene	Naphthene
>44.0	Paraffin	<20.0	Naphthene	Paraffin–naphthene
33.0	Naphthene	>30.0	Paraffin	Naphthene–paraffin

API GRAVITY

Conventional crude oil and heavy oil have also been defined very generally in terms of physical properties. For example, heavy oils were considered those petroleum-type materials that had gravity somewhat less than 20° API, with the heavy oils falling into the API gravity range of 10° to 15° (e.g., Cold Lake crude oil = 12° API) and bitumen falling into the 5° to 10° API range (e.g., Athabasca bitumen = 88 API). Residua vary depending on the temperature at which distillation is terminated. Atmospheric residua are usually in the 10° to 15° API range of, and vacuum residua are in the range of 2° to 8° API.

CARBON DISTRIBUTION

A method for the classification of crude oils can only be efficient, first, if it indicates the distribution of components according to volatility, and second, if it indicates the characteristic properties of the various distillate fractions. The distribution according to volatility has been considered the main property of petroleum, and an γ fractionating column with a sufficient number of theoretical plates may be used for recording a curve in which the boiling point of each fraction is plotted against the percentage by weight.

However, for the characterization of the various fractions of petroleum, the use of the

n.d.M method (n = refractive index, d = density, M =molecular weight; is suggested. This method enables determination of the carbon distribution and thus indicates the percentage of carbon in aromatic structure ($\%C_A$), the percentage of carbon in naphthene structure ($\%C_N$), and the percentage of carbon in paraffin structure ($\%C_P$). The yields over the various boiling ranges can also be estimated; for example, in the lubricating oil fractions the percentage of carbon in paraffin structure can be divided into two parts, giving the percentage of carbon in normal paraffins ($\%C_{nP}$) and the percentage of carbon in paraffin side-chains. The percentage of normal paraffins present in lubricating oil fractions can be calculated from the percentage of normal paraffin carbon ($\%C_{nP}$) by multiplication by a factor that depends on the hydrogen content of the fractions.

VISCOSITY–GRAVITY CONSTANT

This parameter, along with the Universal Oil Products characterization factor, has been used to some extent as a means of classifying crude oils. Both parameters are usually employed to give an indication of the paraffin character of the crude oil, and both have been used, if a subtle differentiation can be made, as a means of petroleum characterization rather than for petroleum classification. Nevertheless, the viscosity–gravity constant (VGC) was one of the early indices proposed to characterize (or classify) oil types:

$$VGC = 10d - 1.0752 \log(\nu - 38) / (10 - \log(\nu - 38))$$

In this equation, d is the specific gravity $60^\circ/60^\circ\text{F}$ and ν is the Saybolt viscosity at 39°C (100°F). For heavy oil, where the low-temperature viscosity is difficult to measure, an alternative formula has been proposed in which the 99°C (210°F) Saybolt viscosity is used, viz:

$$VGC = d - 0.24 - 0.022 \log(\nu - 35.5) / 0.755$$

The two do not agree well for low-viscosity oils. However, the viscosity–gravity constant is of particular value in indicating a predominantly paraffin or cyclic composition. The lower the index number, the more paraffin the feedstock; for example, naphthene lubricating oil

UOP C HARACTERIZATION F ACTOR

This factor is perhaps one of the more widely used derived characterization or classification factors and is defined by the formula:

$$K = (T_B)^{1/3} / d$$

where T_B is the average boiling point in degrees Rankine ($^\circ\text{F} + 460$) and d is the specific gravity $60^\circ/60^\circ\text{F}$. This factor has been shown to be additive on a weight basis. It was originally

devised to show the thermal cracking characteristics of heavy oils ; thus, highly paraffinic oils have K in the range 12.5 to 13.0 and cyclic (naphthene) oils have K in the range 10.5 to 12.5.

RECOVERY METHOD

The generic term heavy oil is often applied to petroleum that has an API gravity of less than 20° and those materials having an API gravity less than 10.8 have been referred to as bitumen. Following this convenient generalization, there has also been an attempt to classify petroleum, heavy oil, and tar sand bitumen using a modified API gravity or viscosity scale. In order to classify petroleum, heavy oil, and bitumen the use of a single parameter such as viscosity is not enough. Other properties such as API gravity, elemental analysis, composition, and the properties of the fluid in the reservoir as well as the method of recovery need to be acknowledged.

POUR POINT

By definition, the pour point is the lowest temperature at which oil will move, pour, or flow when it is chilled without disturbance under definite conditions. In fact, the pour point of oil when used in conjunction with the reservoir temperature gives a better indication of the condition of the oil in the reservoir than the viscosity. Thus, the pour point and reservoir temperature present a more accurate assessment of the condition of the oil in the reservoir, being an indicator of the mobility of the oil in the reservoir. In deed, when used in conjunction with reservoir temperature, the pour point gives an indication of the liquidity of the heavy oil or bitumen and, therefore, the ability of the heavy oil or bitumen to flow under reservoir conditions. In summary, the pour point is an important consideration because, for efficient production, additional energy must be supplied to the reservoir by a thermal process to increase the reservoir temperature beyond the pour point.