## BASIC KNOWLEDGE IN CRUDE OIL AND ITS FRACTIONATING SYSTEM

Crude petroleum or crude oil as produced from the field is a relatively low-value material since, in its native state, it is rarely usable directly. Thus it is usually refined and further processed into a number of products whose total value is many times that of the original oil. The first step in any oil refinery is the separation of the crude oil into various fractions by the process of distillation. These fractions may be products in their own right or may be feedstocks for other refining or processing units.

## 3.1 Characterization of Crude Oil and Its Fractions

Although much progress has been made in identifying the chemical species present in petroleum (refer to Table 1), a complete component-by-component analysis is not practically realizable. For this reason, the composition of any given crude oil or its fractions is characterized in terms of one or more laboratory distillation tests that are summarized in Table 2. A thorough discussion of the equipment and procedures involved is given in Chapter 4 of Ref.4.

### 3.1.1 ASTM Distillations

The ASTM D 86 and D 1160 tests are reasonably rapid batch laboratory distillations involving the equivalent of approximately one equilibrium stage and no reflux except for that caused due to heat

# Table 1  Hydrocarbon analysis of a representative crude - Tia Juana Light

| CRUDE | TIA JUANA LIGHT | SL.121C-AN.69 |
|---|---|---|

| 15/5 Cut Point | °F VT | Gas to 68 | 68 – 158 |
|---|---|---|---|
| 15/5 Cut Point | °C VT | Gas to 20 | 20 – 70 |
| Yield Cut Range | Vol. % | 0.0-1.84 | 1.84-5.81 |
| Yield On Crude | Vol. % | 1.84 | 3.97 |

| 15/5 Cut Point | °F VT | 158-212 | Summary: | | |
|---|---|---|---|---|---|
| 15/5 Cut Point | °C VT | 70-100 | Paraffins | Vol. % | 62.6 |
| Yield Cut Range | Vol. % | 5.9-9.8 | Naphthenes | Vol. % | 32.8 |
| Yield On Crude | Vol. % | 3.9 | Aromatics | Vol. % | 4.6 |

| | Mass Spec. Liq. Vol. % | | Gas Chrom. Liq. Vol. % | |
|---|---|---|---|---|
| | On Naph. | On Crude | On Naph. | On Crude |
| Ethane | 2.2 | 0.04 | | |
| Propane | 20.1 | 0.37 | 0.1 | 0.01 |
| Iso Butane | 13.6 | 0.25 | 0.3 | 0.01 |
| n-Butane | 42.9 | 0.79 | 2.4 | 0.10 |
| Iso Pentane | 13.0 | 0.24 | 13.4 | 0.53 |
| n-Pentane | 8.2 | 0.15 | 24.7 | 0.98 |
| 2,2-Dimethylbutane | | | 0.9 | 0.04 |
| 2,3-Dimethylbutane | | | 2.1 | 0.08 |
| 2-Methylpentane | | | 16.0 | 0.64 |
| 3-Methylpentane | | | 9.8 | 0.39 |
| Cyclopentane | | | 2.4 | 0.10 |
| n-Hexane | | | 20.2 | 0.80 |
| 2,2-Dimethylpentane | | | 0.1 | 0.01 |
| 2,4-Dimethylpentane | | | 0.2 | 0.01 |
| Methylcyclopentane | | | 4.7 | 0.19 |
| 2-Methylhexane | | | 0.1 | 0.01 |
| 2,3-Dimethylpentane | | | | |
| 3-Methylhexane | | | 0.1 | 0.01 |
| Cyclohexane | | | 1.0 | 0.04 |
| Benzene | | | 1.5 | 0.06 |
| Summary: | | | | |
| Paraffins | Vol. % | | 90.4 | |
| Naphthenes | Vol. % | | 8.1 | |
| Aromatics | Vol. % | | 1.5 | |

| GAS CHROMATOGRAPHY | Vol. % On Naphtha | | Vol. % On Naphtha |
|---|---|---|---|
| Methane | | 2,4-Dimethylhexane | 0.2 |
| Ethane | | Methylcyclohexane | 7.7 |
| Propane | | 3,3-Dimethylhexane | |
| Isobutane | | 2,2,3-Trimethylpentane | |
| n-Butane | | 2,3,4-Trimethylpentane | |
| Isopentane | 0.3 | 2-Methyl-3-Ethylpentane | |
| n-Pentane | 0.3 | 1-Trans-2-Cis- | |
| 2,2-Dimethylbutane | | 4-Trimethylcyclopentane | 0.2 |
| 2,3-Dimethylbutane | | Ethylcyclopentane | 0.6 |
| 2-Methylpentane | 1.8 | 1-Trans-2-Cis- | |
| 3-Methylpentane | 1.9 | 3-Trimethylcyclopentane | 0.1 |
| Cyclopentane | | 2,3-Dimethylhexane | |
| n-Hexane | 11.1 | 2-Methylheptane | 0.2 |
| 2,2-Dimethylpentane | 0.3 | 4-Methylheptane | |
| 2,4-Dimethylpentane | 1.0 | 3,4-Dimethylhexane | |
| 2,2,3-Trimethylbutane | | 3-Methylheptane | |
| Methylcyclopentane | 5.9 | 3-Ethylhexane | |
| 3,3-Dimethylpentane | 0.2 | 1-Cis-3-Dimethylcyclohexane | |
| 2-Methylhexane | 9.1 | 1-Trans-4-Dimethylcyclohexane | |
| 2,3-Dimethylpentane | 3.6 | 1,1-Dimethylcyclohexane | |
| 3-Methylhexane | 11.1 | 1-Methyl-Trans- | |
| Cyclohexane | 8.1 | 3-Ethylcyclopentane | |
| 2,2,4-Trimethylpentane | | 1-Methyl-Cis- | |
| 1,1-Dimethylcyclopentane | 1.5 | 3-Ethylcyclopentane | |
| 3-Ethylpentane | 1.0 | 1-Methyl-Trans- | |
| 1-Cis-3-Dimethylcyclopentane | 2.3 | 2-Ethylcyclopentane | |
| 1-Trans-3-Dimethylcyclopentane | 2.1 | n-Octane | |
| 1-Trans-2-Dimethylcyclopentane | 3.8 | 2,2,4-Trimethylhexane | |
| n-Heptane | 20.3 | 1-Trans-2-Dimethylcyclohexane | |
| 1-Cis-2-Dimethylcyclopentane | 0.3 | 2,4,4-Trimethylhexane | |
| Benzene | 1.7 | 2,3,5-Trimethylhexane - | |
| 2,2-Dimethylhexane | | Toluene | 2.9 |
| 1,1,3-Trimethylcyclopentane | 0.2 | 1-Trans-3-Dimethylcyclohexane | |
| 2,5-Dimethylhexane | 0.2 | 1-Cis-4-Dimethylcyclohexane | |

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losses. Apparatus typical of the D 86 test is shown in Fig.1. It consists of a heated 100 mL or 125 mL Engler flask containing a calibrated thermometer of suitable range to measure the temperature of the vapor at the inlet to the condensing tube, an inclined brass condenser in a cooling bath using a suitable coolant, and a graduated cylinder for collecting the distillate. A stem correction is not applied to the temperature reading. Related tests using similar apparatuses are the D 216 test for natural gasoline and the Engler distillation.

In the widely used ASTM D 86 test, 100 mL of sample is charged to the flask and heated at a sufficient rate to produce the first drop of distillate from the lower end of the condenser tube in from 5 to 15 min, depending on the nature of the sample. The temperature of the vapor at that instant is recorded as the initial boiling point (IBP). Heating is continued at a rate such that the time from the IBP to 5 volume percent recovered of the sample in the cylinder is 60 to 75 sec. Again, vapor temperature is recorded. Then, successive vapor temperatures are recorded for from 10 to 90 where percent recovered in intervals of 10, and at 95 percent recovered, with the heating rate adjusted so that 4 to 5 mL are collected per minute. At 95 percent recovered, the burner flame is increased if necessary to achieve a maximum vapor temperature referred to as the end point (EP) in from 3 to 5 additional min. The percent recovery is reported as the maximum percent recovered in the cylinder. Any residue remaining in the flask is reported as percent residue, and percent loss is reported as the difference between 100 mL and the sum of the percent recovery and percent residue. If the atmospheric test

Table 2  Laboratory Distillation Tests (41).

| Test name | Reference | Main applicability |
|---|---|---|
| ASTM (atmospheric) | ASTM D 86 | Petroleum fractions or products, including gasolines, turbine fuels, naphthas, kerosines, gas oils, distillate fuel oils, and solvents that do not tend to decompose when vaporized at 760 mmHg |
| ASTM [vacuum, often 10 torr (1.3 kPa)] | ASTM D 1160 | Heavy petroleum fractions or products that tend to decompose in the ASTM D 86 test but can be partially or completely vaporized at a maximum liquid temperature of 750°F (400°C) at pressures down to 1 torr (0.13 kPa) |
| TBP [atmospheric or 10 torr (1.3 kPa)] | Nelson,* ASTM D 2892 | Crude oil and petroleum fractions |
| Simulated TBP (gas chromatography) | ASTM D 2887 | Crude oil and petroleum fractions |
| EFV (atmospheric, superatmospheric, or subatmospheric) | Nelson† | Crude oil and petroleum fractions |

*Nelson, *Petroleum Refinery Engineering*, 4th ed., McGraw-Hill, New York, 1958, pp. 95–99.
†Ibid., pp. 104–105.



Fig.1  ASTM distillation apparatus (41).

pressure P is other than 101.3 kPa (760 torr), temperature readings may be adjusted to that pressure by the Sidney Young equation, which in °F is

$$T_{760} = T_P + 0.00012(760 - P)(460 + T_P) \qquad (1)$$

Another pressure correction for percent loss can also be applied, as described in the ASTM test method.

Although most crude oil can be heated to 600°F without noticeable cracking, when ASTM temperatures exceed 475°F, fumes may be evolved, indicating decomposition, which may cause low thermometer readings. In that case, the following correction may be applied

$$T_{corr} = -10^{-1.587+0.004735T} \qquad (2)$$

where    T    = measured temperature, °F

$T_{corr}$ = correction to be added to T, °F

At 500 and 600°F, the corrections are 6 and 18°F respectively.

As discussed by Nelson (4), virtually no fractionation occurs in an ASTM distillation. Thus, components in the mixture do distill one by one in the order of their boiling points but as mixtures of successively higher boiling points.  The IBP, EP, and intermediate points have little theoretical significance, and, in fact, components boiling below the IBP and above EP are present in the sample.  Nevertheless, because ASTM distillations are quickly conducted, have been successfully automated, require only a small sample, and are quite reproducible, they are widely used for comparison and as a basis for

specifications on a large number of petroleum intermediates and products, including many solvents and fuels. Typical ASTM curves for several such products are shown in Fig.2.

### 3.1.2 TBP Distillations

True-boiling-point (TBP) distillations are normally run on crude oils and not on petroleum fractions. This method is basically a batch distillation using a large number of stages and a high reflux -to-distillate ratio so that the temperature at any point on the temperature-volumetric yield curve represents the actual boiling point of the hydrocarbon material present at that volume percentage point. Thus, data from a TBP distillation test provides a much better theoretical basis for characterization. If the sample contains compounds that have moderate differences in boiling points such as in a light gasoline containing light hydrocarbons (e.g., iso-butane, n-butane, iso-pentane, etc.), a plot of overhead-vapor-distillate temperature versus percent distilled in a TBP test would appear in the form of steps as in Fig.3. However, if the sample has a higher average boiling range in which the number of close-boiling isomers increases, the steps become indistinct and a TBP curve such as that in Fig.4 results. Because the degree of separation for a TBP distillation test is much higher than for an ASTM distillation test, the IBP is lower and the EP is higher for the TBP method when compared with the ASTM method, as shown in Fig.4.

A standard TBP laboratory-distillation-test method has not been well accepted. Instead, as discussed by Nelson (4), batch distillation equipment that can achieve a good degree of fractionation
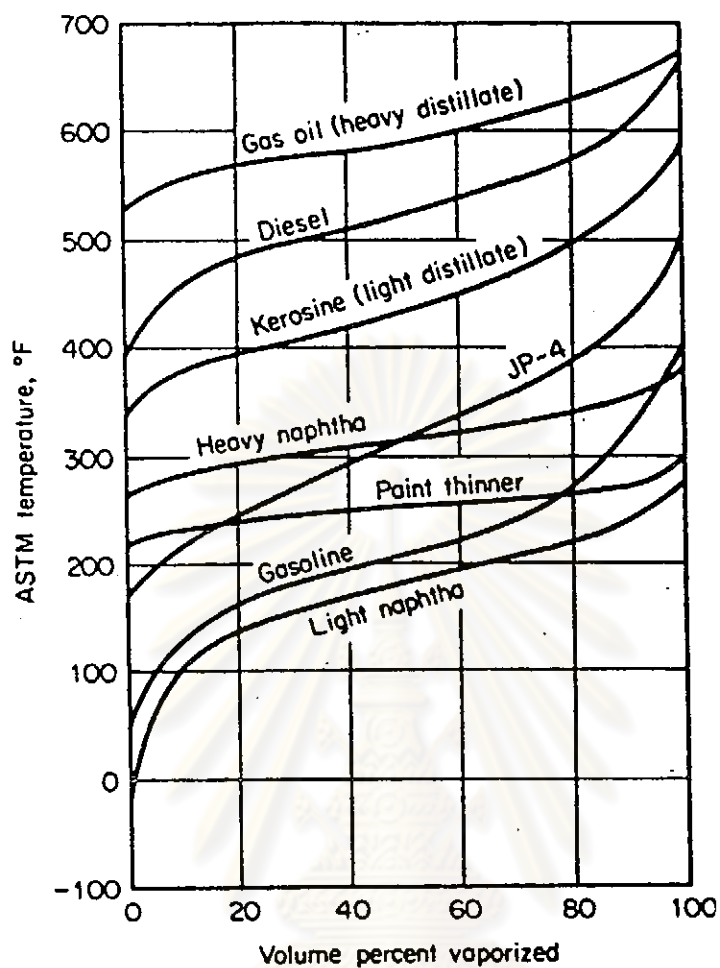
Fig.2  Representative ASTM D 86 distillation curves (41).
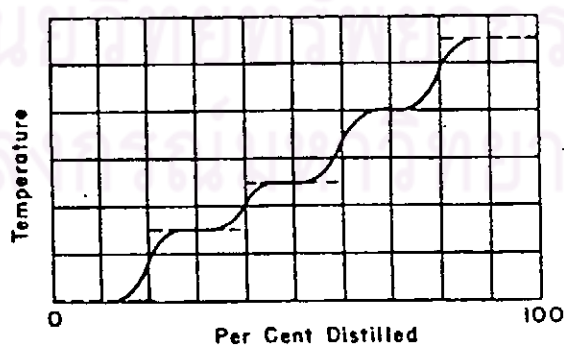


Fig.3  Variation of boiling temperature with percent distilled in
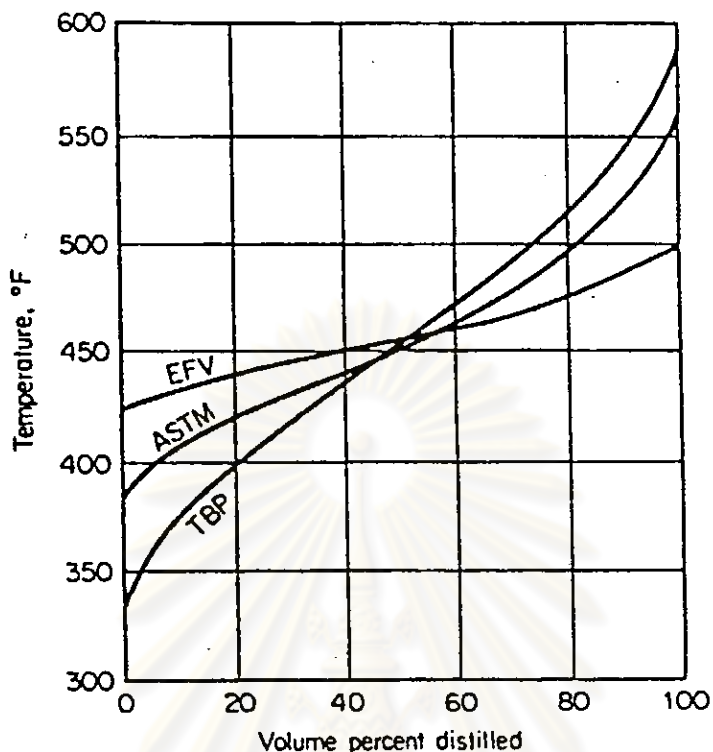true-boiling-point distillation of light hydrocarbons (41).

Fig.4 Comparison of ASTM, TBP, and EFV distillation curves for kerosine (41).

is usually considered suitable. In general, TBP distillations are conducted in columns with 15 to 100 theoretical stages at reflux ratios of 5 or greater. Thus, the new ASTM D 2892 test method, which involves a column with 14 to 17 theoretical stages and a reflux ratio of 5, essentially meets the minimum requirements. Distillate may be collected at a constant or a variable rate. Operation may be at 101.3 kPa pressure or at a vacuum at the top of the column as low as 0.067 kPa for high-boiling fractions, with 1.3 kPa being common. Results from vacuum operation are extrapolated to 101.3 kPa by the vapor-pressure correlation of Maxwell and Bonnel (42), and in the ASTM D 2892 test method, it includes a correction for the nature of the sample in terms of the UOP characterization factor.

### 3.1.3 EFV Distillations

A third fundamental type of laboratory distillation, which is the most tedious to perform of the three types of laboratory distillations, is equilibrium-flash-distillation (EFV), for which no standard test exists. The sample is heated in such a manner that the total vapor produced remains in contact with the total remaining liquid until the desired temperature is reached at a set pressure. The volume percent vaporized at these conditions is recorded. To determine the complete flash curve, a series of runs at a fixed pressure is conducted over a range of temperature sufficient to cover a range of vaporization from 0 to 100 percent. As seen in Fig.4, the component separation achieved by an EFV distillation is much less than by the ASTM or TBP distillation tests. The initial and final EFV points are the bubble point and the dew point respectively of the sample. If desired, EFV curves can be established at a series of pressures.

### 3.1.4 Interrelation between ASTM, TBP and EFV Distillation Curves

Because of the time and expense involved in conducting laboratory distillation tests of all three basic types, it has become increasingly common to use empirical correlations to estimate the other two distillation curves when either the ASTM, TBP, or EFV curve is available. Preferred correlations given in the following are based on the work of Edmister (43) and Maxwell (44) as shown in Fig.5-9.

For the interconversion between ASTM and TBP distillations of topping column sidestream products, it is helpful to have an empirical expression for the correlation. Nelson (45) found that the preceding types of distillation, a sigmoidal-shaped curve results when-

ever values of the dependent variable, y (or temperature, °F), are plotted against the independent variable, x cumulative-percent-less-than, (CPLT), (or volume percent distilled), on arithmetic coordinate graph paper. This sigmoidal-shaped curve can be transformed into a straight line when value of x are plotted on a probability scale. This method is called Nelson's method for extrapolating crude oil TBP curves into the high boiling range.

Values of x on the linear abscissa scale are quickly transformed into values of $x^*$ on the probability scale by using Eq.(3)-(5) from Hastings (46);

$$q = x/100 \qquad \text{(when } x < 50\%\text{)}$$

$$q = 1 - x/100 \qquad \text{(when } x > 50\%\text{)} \qquad (3)$$

$$n = \sqrt{\ln(1/q^2)} \qquad (4)$$

$$x^* = n - (a_0 + a_1 n)/(1 + a_2 n + a_3 n^2) \qquad (5)$$

where,

$$a_0 = 2.30753$$

$$a_1 = 0.27061$$

$$a_2 = 0.99229$$

$$a_3 = 0.04481$$

For values of x that are less than 50%, the sign of $x^*$ is changed from positive to negative. The transformation which linearizes the y versus CPLT curve uses the method of least squares to fit a best straight line through the transformed data points and the equation of that line is expressed as

$$y = mx^* + b \qquad (6)$$

where   m = slope of the least squares fit line through the probability paper plotted data points,
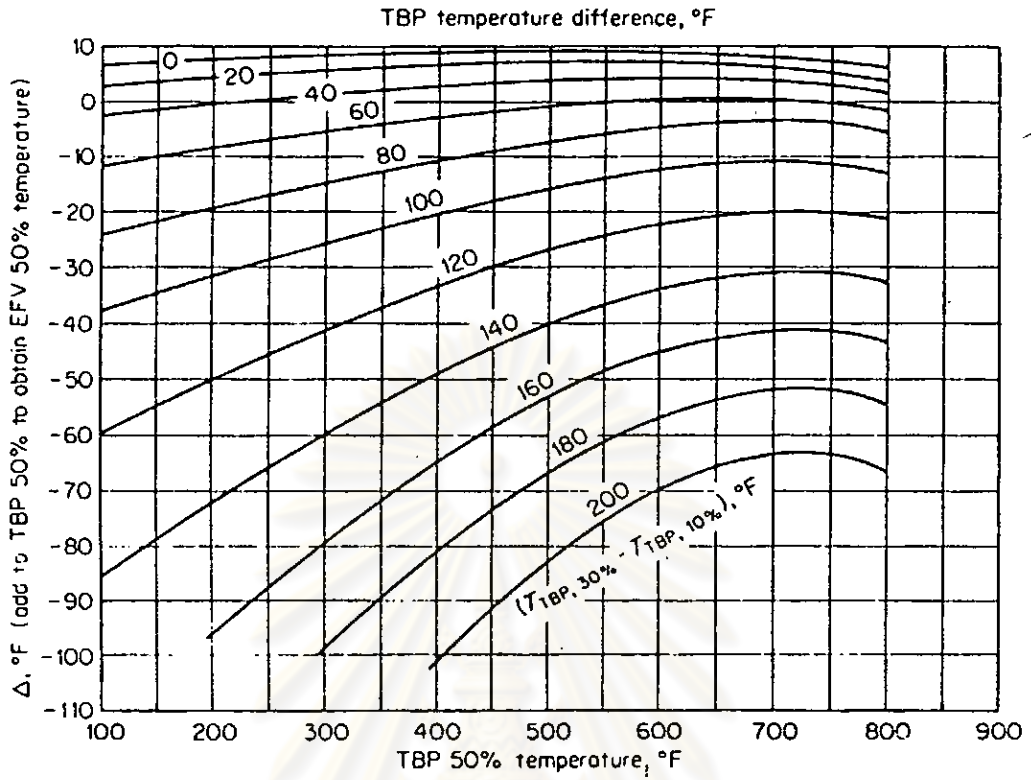
b = y-intercept of that line.

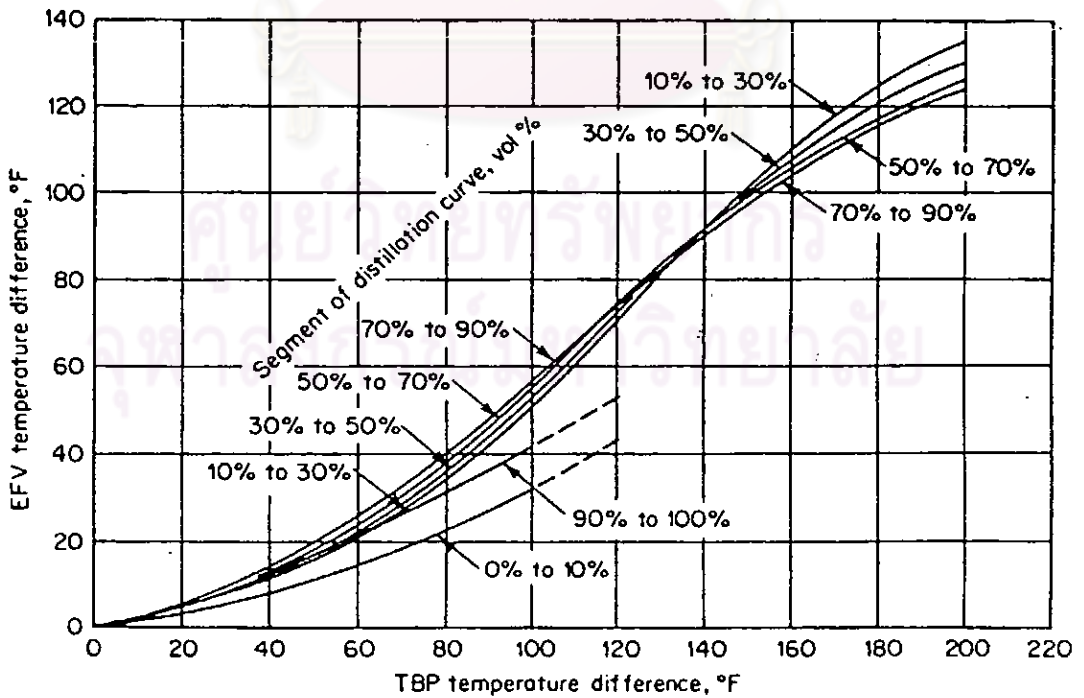Fig.5  TBP 50% temperature versus EFV 50% temperature (43).



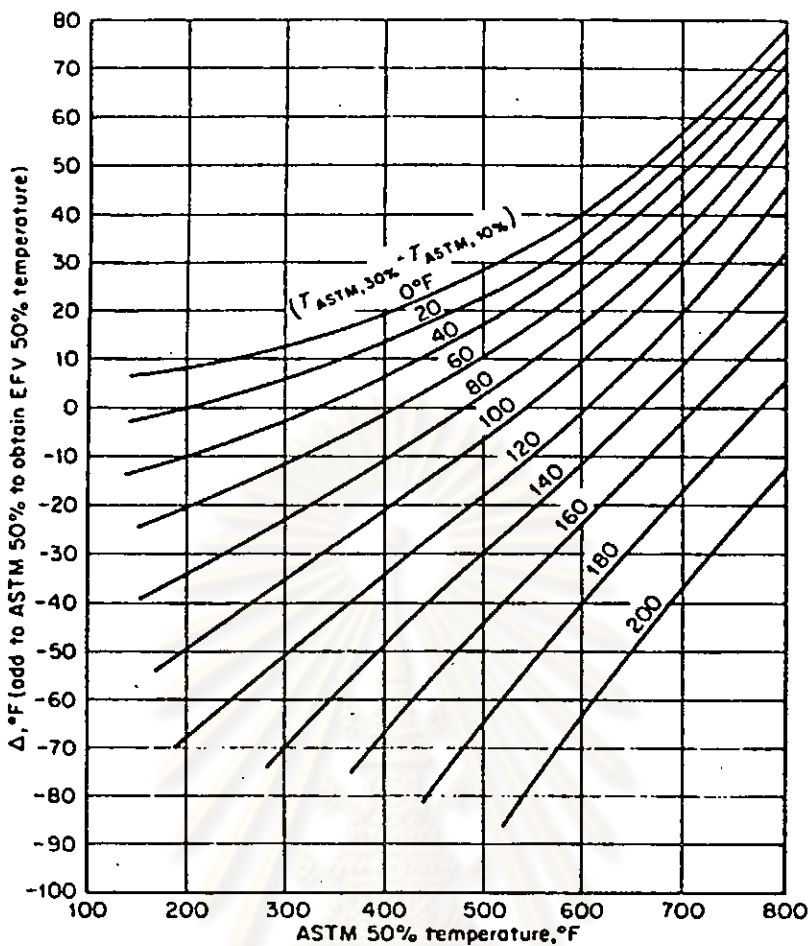Fig.6  TBP temperature difference versus EFV temperature difference (43).

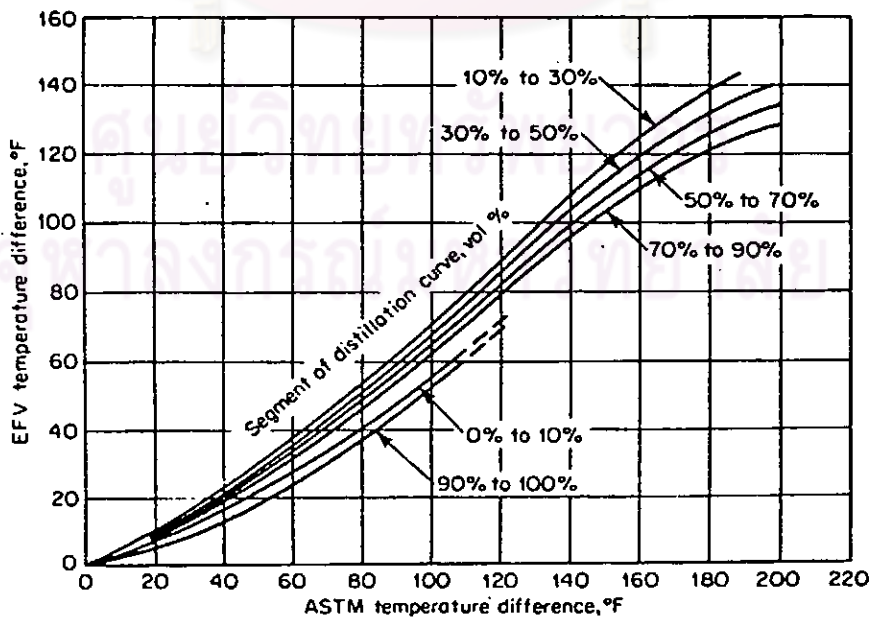Fig.7 ASTM 50% temperature versus EFV 50% temperature (43).



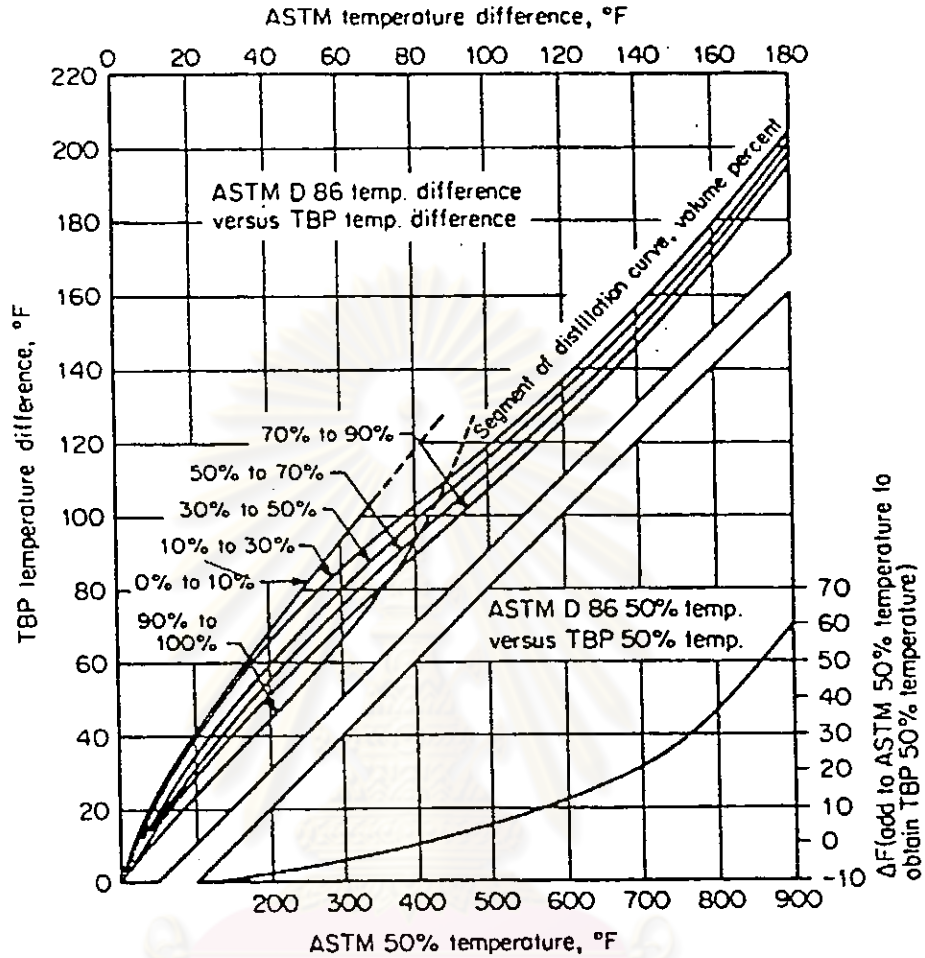Fig.8 ASTM temperature difference versus EFV temperature difference (43).

Fig.9 Relationship between ASTM and TBP distillation curves (43).

Gandbhir and Virk (47) proposed a linear relationship between the slopes of the probability-graph-paper plotted TBP and ASTM distillations;

$$m_t = 1.16 m_a + 10.2 \qquad (7)$$

where $m_t$ = slope of the least-squares-fit line through the probability-paper plotted TBP distillation data points,

$m_a$ = slope of the least-squares-fit line through the probability-paper plotted ASTM distillation data points.

3.1.5 API Gravity

Gravity of a crude oil or petroleum fraction is generally measured by the ASTM D 287 test or the equivalent ASTM D 1298 test and may be reported as specific gravity (Sp.Gr.) 60/60°F and referred to water at 60°F or, more commonly, as API gravity, which is defined as

$$\text{API gravity} = \frac{141.5}{\text{Sp.Gr.}(60/60°F)} - 131.5 \qquad (8)$$

Water, thus, has an API gravity of 10.0, and most crude oils and petroleum fractions have values of API gravity in the range of 10 - 80. Light hydrocarbons (n-pentane and lighter) have values of API gravity ranging upward from 92.8. Relations between pounds per gallon, specific gravity, and API gravity are tabulated in Appendix A.

3.1.6 UOP Characterization Factor

There are many indexes, factors, etc., used in classifying crude oils and their products. The most widely used index is the UOP Characterization Factor, UOP-K, as given by

$$\text{UOP-K} = \sqrt[3]{T_B} / \text{Sp.Gr.}(60/60°F) \qquad (9)$$

where $T_B$ = mean average boiling point, °R = (°F + 460)

Characterization factor is given in Fig.10 as a function of gravity (°API) and boiling point (°F) for hydrocarbons and petroleum fractions. Values of UOP-K for n-hexane, 1-hexene, cyclohexene, and benzene are 12.82, 12.49, 10.99, and 9.73 respectively. Thus,

Fig.10 Characterization Factor
VS boiling point and gravity
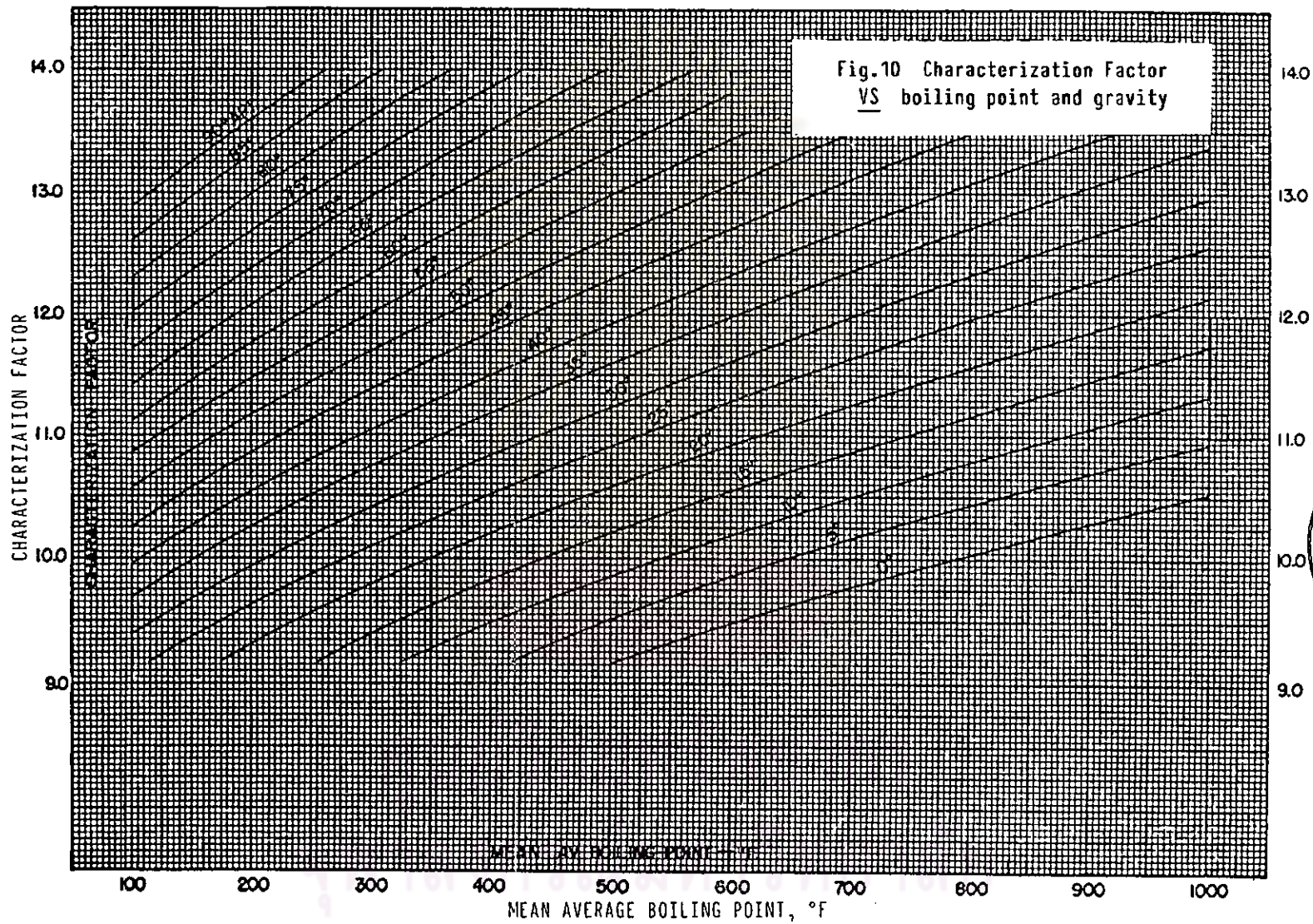
paraffins with their lower values of specific gravity tend to have high values, and aromatics tends to have low values of UOP-K.

The UOP-K has been useful in correlating many properties, among which are hydrogen content, viscosity, aniline point, molecular weight, critical temperature,etc., so that almost any laboratory data can be used to estimate the factor.

### 3.1.7 Crude Assay

The complete and definitive analysis of a crude oil, usually called a " crude assay ", is considerably more detailed than a TBP curve and a whole crude API gravity. A complete crude assay will contain some or all of the following (6);

    a. Whole crude gravity, viscosity, sulfur content, pour point, etc.

    b. TBP curve, mid-volume plot of gravity, viscosity, sulfur ,etc.

    c. Light-ends analysis up through $C_8$ or $C_9$.

    d. Properties of fractions ( naphthas, middle distillates, gas oils and residue )-yield as volume percent, gravity, sulfur content, viscosity, octane number, etc.

    e. Properties of lube distillates ( only if the crude is suitable for the manufacture of lube basestocks ).

    f. Properties of asphalts ( only if the residue have suitable characteristics for preparation of asphalts ).

    g. Details studies of fractions for various properties,e.g. octane number versus yield for naphthas, or viscosity versus yield for lubestocks.
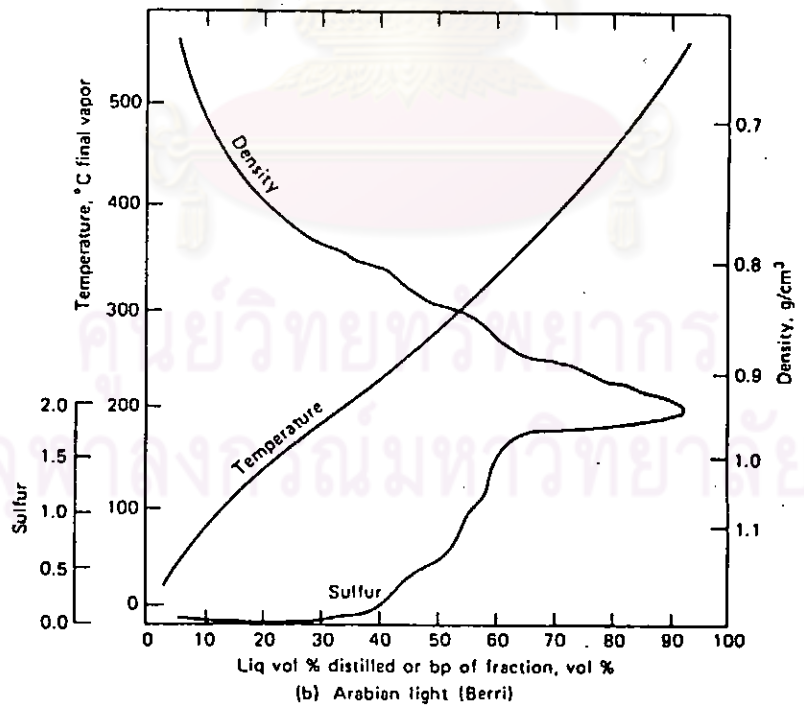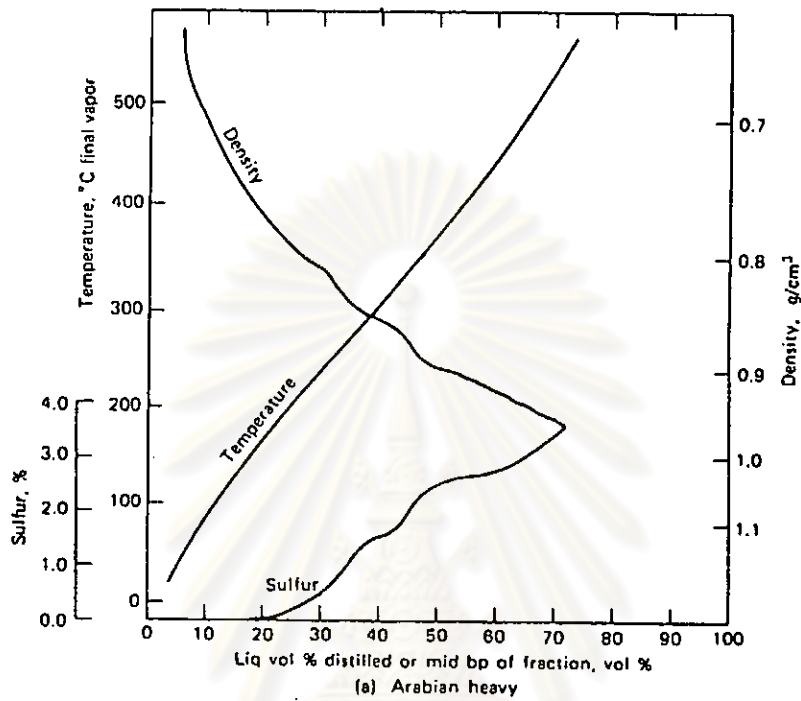
Fig. 11  Properties of representative crudes. (a) Arabian heavy (b) Arabian light
(Berri) (48)

Table 3  Properties of representative crude - Arabian Crudes (48).

| | Heavy | Light[b] |
|---|---|---|
| *Crude* | | |
| specific gravity | 0.886 | 0.831 |
| sulfur, wt % | 2.84 | 1.10 |
| pour point, °C | −34 | −34 |
| Reid vapor pressure, kPa[c] | 160 | 140 |
| viscosity, mm²/s (= cSt) | | |
| at 21°C | 35.8 | 5.65 |
| at 38°C | 18.9 | 3.78 |
| *Light naphtha* | | |
| range, °C | 20–100 | 20–100 |
| yield, vol % | 7.9 | 10.5 |
| specific gravity | 0.669 | 0.677 |
| sulfur, wt % | 0.0028 | 0.055 |
| Reid vapor pressure, kPa[c] | 170 | 150 |
| paraffins, vol % | 89.6 | 87.4 |
| cycloparaffins, vol % | 9.5 | 10.7 |
| aromatic material | 0.9 | 1.9 |
| RON, clear | 59.7 | 54.7 |
| *Heavy naphtha* | | |
| range, °C | 100–150 | 100–150 |
| yield, vol % | 6.8 | 9.4 |
| specific gravity | 0.737 | 0.744 |
| sulfur, wt % | 0.018 | 0.057 |
| paraffins, vol % | 70.3 | 66.3 |
| cycloparaffins, vol % | 21.4 | 20.0 |
| aromatic material | 8.3 | 13.7 |
| *Kerosene* | | |
| range, °C | 150–235 | 150–235 |
| yield, vol % | 12.5 | 18.4 |
| specific gravity | 0.787 | 0.788 |
| sulfur, wt % | 0.19 | 0.092 |
| paraffins, vol % | 58.0 | 58.9 |
| cycloparaffins | 23.7 | 20.5 |
| aromatic material, vol % | 18.3 | 20.6 |
| freeze point, °C | −53 | −55 |
| smoke point, mm | 26 | 26 |
| aniline point, °C | 59 | 56 |
| viscosity, mm²/s (= cSt) | | |
| at 34°C | 4.74 | 5.09 |
| at 38°C | 1.12 | 1.13 |
| *Light gas oil* | | |
| range, °C | 235–343 | 235–343 |
| yield, vol % | 16.4 | 21.1 |
| specific gravity | 0.846 | 0.838 |
| sulfur, wt % | 1.38 | 0.81 |
| pour point, °C | −15 | −12 |
| aniline point, °C | 69 | 74 |
| viscosity, mm²/s (= cSt) | | |
| at 38°C | 3.65 | 3.34 |
| at 99°C | 1.40 | 1.32 |
| *Heavy gas oil* | | |
| range, °C | 343–565 | 343–565 |
| yield, vol % | 26.3 | 30.6 |
| specific gravity | 0.923 | 0.905 |
| sulfur, wt % | 2.88 | 1.79 |
| pour point, °C | 32 | 38 |
| aniline point, °C | 78 | 91 |
| viscosity, mm²/s (= cSt) | | |
| at 38°C | 62.5 | 49.0 |
| at 99°C | 7.05 | 6.65 |

Table 3 ( continued ).

| | Heavy | Light[b] |
|---|---|---|
| *Residual oil* | | |
| range, °C | >343 | >343 |
| yield, vol % | 53.1 | 38.0 |
| specific gravity | 0.984 | 0.924 |
| sulfur, wt % | 4.35 | 2.04 |
| pour point, °C | 13 | 24 |
| Conradson carbon, wt % | 13.2 | 4.5 |
| viscosity, mm²/s (= cSt) | | |
| at 38°C | 5400 | 146 |
| at 99°C | 106 | 12.4 |
| *Residual oil* | | |
| range, °C | >565 | >565 |
| yield, vol % | 26.8 | 7.4 |
| specific gravity | 1.044 | 0.990 |
| sulfur, wt % | 5.60 | 3.0 |
| pour point, °C | 49 | 27 |
| Conradson carbon, wt % | 24.4 | 19.0 |
| viscosity, | | |
| mm²/s (= cSt), at 99°C | 13,400 | 393 |
| furol, s, at 135°C | 490 | 40.1 |
| metals, ppm | | |
| vanadium | 171 | 12 |
| nickel | 53 | 7 |
| iron | 28 | 36 |

[a] Ref. 4.
[b] Berri, Saudi Arabia.
[c] To convert kPa to psi, multiply by 0.145.

h. EFV curve run at atmospheric pressure and/or phase dia-

gram, although this is rarely done.

Much of this information is of little use in design work

but is of great importance to a refiner or to a crude oil purchaser.

Table 3 and Fig.11 give typical assay of representative crudes (48).

3.2 Crude Oil Refinery Distillation

In most refineries, this process is carried out in two stages.

The oil is first heated to the maximum temperature allowable for the

crude being processed and for the operation being practiced and then

fed to a fractionating column which operates at slightly above atmos-

pheric pressure. This column is usually called the " atmospheric

column " or " topping column ". It yields several distillate products and a bottom product which is the residual liquid material unable to vaporize under the conditions of temperature and pressure existing in the topping column. This bottom liquid is then reheated to the maximum allowable temperature - usually higher than the maximum temperature allowed for the feed to the topping column - and fed to a fractionating column which operates at subatmospheric pressure. This column is usually called the " vacuum column ". Typical equipment configurations for the distillation of crude oil in a crude unit is shown in Fig.12.

Although the process of crude oil distillation has been practiced for more than 100 years, the design and solution of these units is still accomplished almost exclusively on an empirical basis. This thesis warrants special consideration for the following reasons:

1) Crude oil is of exceedingly complex composition, consisting of many different types of hydrocarbon and sometimes of inorganic and other organic compounds. The number of carbon atoms in the components may range from 1 to more than 50, so that the compounds may exhibit atmospheric-pressure boiling points from -259°F to more than 1300°F. In a given boiling range, the number of different compounds that exhibit only small differences in volatility multiplies rapidly with increasing boiling point. For example, 16 of the 18 octane isomers boil within a range of only 22°F (41).

2) Products from the distillation of crude oil are themselves complex mixtures. The character and yields of these products vary widely, depending upon the source of the feedstock. Even crude oils from the same locality may exhibit marked variations.

Fig.12  Crude units (41).

SI Conversion: °C = (°F − 32)/1.8; kPa = psia × 6.89; kg = lb × 0.454; GJ = MMBtu × 1.055

'OVERFLASH SET AT 3 PERCENT ON FEED

3) The scale of crude distillation operations is generally huge, and operations are conducted in large pieces of equipment that can consume large quantities of energy. Therefore optimization of design and operation is very important and frequently leads to a relatively complex equipment configuration.

### 3.2.1 Basic Processes for Topping Column

If the salt content of the crude oil is greater than 10 lb/1,000 bbl (expressed as NaCl), the crude requires desalting to minimize fouling and corrosion caused by salt deposition on heat transfer surfaces and acids formed by decomposition of the chloride salts. In addition, some metals which can cause catalyst deactivation in catalytic processing units are partially removed in the desalting process.

After desalting, the crude oil is pumped through a series of heat exchangers and its temperature raised to about 550°F by heat exchange with product and reflux streams. It is then further heated to about 750°F in a furnace (i.e. direct-fired heater or "pipestill") and charged to the flash zone of the topping column. The furnace discharge temperature is sufficiently high (650 to 750°F) to cause vaporization of all products withdrawn above the flash zone plus about 20 percent of the bottom product. This 20 percent "overflash" allows some fractionation to occur on the trays just above the flash zone by providing internal reflux in excess of the sidestream withdrawals.

Because of the continuously increasing temperature of crude oil as more and more of the material vaporized and because the charge is usually heated to its maximum allowable temperature prior to en-

tering the flash zone, it is not feasible to use a reboiler in crude distillation. Another way of stating the same principle is that the total heat input required by the process must be contained in the feed as it leaves the crude furnace.

Reflux is provided by condensing the column overhead vapors and returning a portion of the liquid to the top of the tower, and by pumparound and pumpback streams lower in the column. Each of the side stream products removed from the column decreases the amount of re-flux below the point of drawoff. Maximum reflux and fractionation is obtained by removing all heat at the top of tower, but this results in an inverted cone-shape liquid loading which requires a very large diameter at the top of the column. To reduce the top diameter of the column and to even the liquid loading over the length of the column, intermediate heat removal streams are used to generate reflux below the sidestream removal points. To accomplish this, liquid is removed from the column, cooled by a heat exchanger, and returned to the co-lumn or, alternatively, a portion of the cooled sidestream may be returned to the column. This cold stream condenses more of the vapors coming up the tower and thereby increases the reflux rate below that point.

Although the topping columns do not normally use reboilers, several trays are generally incorporated below the flash zone and steam is introduced below the tray to strip any remaining gas oil from the liquid in the flash zone and to produce a high flash point bottoms. The steam reduces the partial pressure of the hydrocarbons and thus lowers the required vaporization temperature.

The topping column normally contains 30 to 50 fractionation

trays. Separation of the complex mixtures in crude oil is relatively easy and generally 4 to 8 trays are needed for each sidestream product plus the same number above and below feed plate. Thus, a topping column with four liquid sidestream drawoffs will require from 30 to 42 trays.

The liquid sidestreams withdrawn from the column will contain low-boiling components which lower the flash point, because the lighter products pass through the heavier products and are in equilibrium with them on every tray. These "light ends" are stripped from each sidestream in a separate small stripping column containing 4 to 10 trays with steam introduced under the bottom tray. The steam and stripped light ends are vented back into the vapor zone of the topping column above the corresponding side-draw tray.

The overhead condenser on the topping column condenses the pentane-and-heavier fraction of the vapors that pass out of the top of the column. This is the light gasoline portion of the overhead, containing some propane and butanes and essentially all of the higher boiling components in the column overhead vapor. Some of this condensate is returned to the top of the column as reflux, and the remainder is sent to the stabilization section of the refinery gas plant where the butanes and propane are separated from the $C_5$-180°F LSR gasoline.

3.2.2 Products of Topping Column

Main products produced from a typical topping column consist of a noncondenseable light-hydrocarbon gas, a light naphtha (LSR gasoline), a heavy naphtha (HSR gasoline), a light distillate

TABLE 4

Boiling Ranges of Typical Crude Oil Fractions

| Fraction | Boiling Ranges | |
| --- | --- | --- |
| | ASTM (°F) | TBP (°F) |
| Butanes and lighter | | |
| Light straight-run gasoline (LSR) | 90-220 | 90-190 |
| Naphtha (heavy straight-run gasoline) | 180-400 | 190-380 |
| Kerosine | 330-540 | 380-520 |
| Light gas oil (LGO) | 420-640 | 520-610 |
| Atmospheric gas oil | 550-830 | 610-800 |
| Vacuum gas oil (VGO) | 750-1,050 | 800-1,050 |
| Vacuum reduced crude | 1,000$^+$ | 1,050$^+$ |

TABLE 5

TBP Cut Points for Various Crude Oil Fractions

| Cut | IBP (°F) | EP (°F) | Processing use |
| --- | --- | --- | --- |
| LSR gasoline | 90 | 180 | Min light gasoline cut |
| | 90 | 190 | Normal LSR cut |
| | 80 | 220 | Max LSR cut |
| HSR gasoline | 180 | 380 | Max reforming cut |
| (naphtha) | 190 | 330 | Max jet fuel opr |
| | 220 | 330 | Min reforming cut |
| Kerosine | 330 | 520 | Max kerosine cut |
| | 330 | 480 | Max jet-50 cut |
| | 380 | 520 | Max gasoline operation |
| Light gas oil | 420 | 610* | Max diesel fuel |
| | 480 | 610* | Max jet fuel |
| | 520 | 610* | Max kerosine |
| Heavy gas oil (HGO) | 610 | 800 | Catalytic cracker feed |
| Vacuum gas oil | 800 | 1,050 | Deasphalter or catalytic cracker feed |
| | 800 | 950 | Catalytic cracker feed |

Note: In some specific locations, economics can dictate that all material between 330°F IBP and 800°F EP be utilized as feed to a hydrocracker.

*For maximum No. 2 diesel-fuel production, end points as high as 650°F can be used.

(kerosine), a heavy distillate (diesel oil or gas oil), and a bottom residual of components whose TBP exceeds approximately 800°F. The fraction cut points and boiling ranges of these and other fractions are given in Tables 4 and 5.