

Chapter 2

Literature Review and Theoretical Background

2.1. Introduction

Hydrocarbon systems are mixtures of organic compounds which exhibit multiphase behaviour over wide ranges of pressures and temperatures. These hydrocarbon accumulations may occur in the gaseous state, the liquid state, the solid state, or in various combinations of gas, liquid, and solid. These differences in phase behaviour coupled with the physical properties of reservoir rock that determine which gas and liquid are transmitted or retained, study the behaviour and characteristics of a petroleum reservoir and to determine the course of future development and production that would maximize the profit.

2.2. Reservoir's Classification

Petroleum reservoirs are broadly classified as oil or gas reservoirs. These broad classifications are further subdivided depending on:

- The composition of the reservoir hydrocarbon mixture
- Initial reservoir pressure and temperature
- Pressure and temperature of the surface production

2.3. Pressure-Temperature Diagram

Figure 2-1 shows a typical pressure-temperature diagram of multicomponent systems with a specific overall composition. Although a different hydrocarbon system would have a different phase diagram, the general configuration is similar.

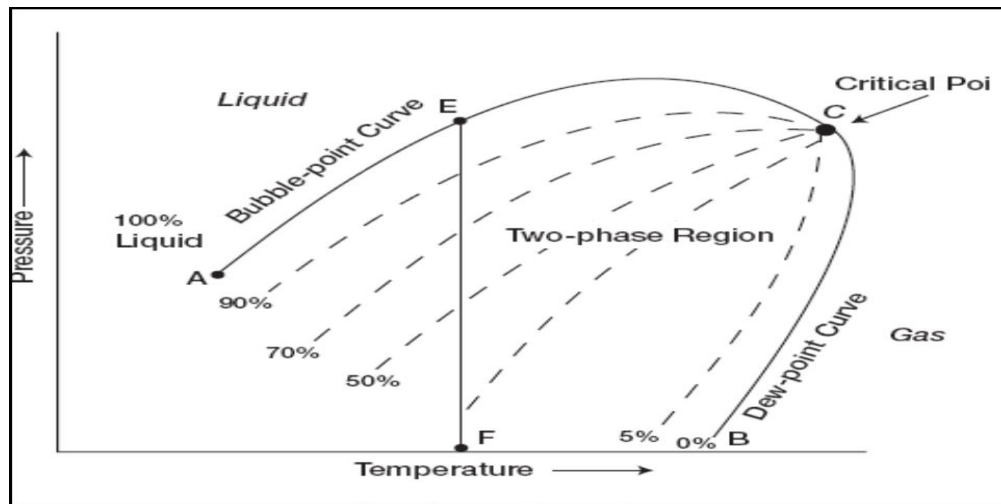


Figure 2-1: typical P-T diagram for multicomponent system (Tarek Ahmed, 2001)

These multicomponent pressure-temperature diagrams are essentially used to:

- Classify reservoirs
- Classify the naturally occurring hydrocarbon systems
- Describe the phase behavior of the reservoir fluid

To fully understand the significance of the pressure-temperature diagrams, it is necessary to identify and define the following key points on These diagrams:

- **Cricondetherm (Tct):** The Cricondetherm is defined as the maximum temperature above which liquid cannot be formed regardless of pressure (point E). The corresponding pressure is termed the Cricondetherm pressure p_{ct} .
- **Cricondenbar (pcb):** The Cricondenbar is the maximum pressure above which no gas can be formed regardless of temperature (point D). The Corresponding temperature is called the Cricondenbar temperature T_{cb} .
- **Critical point:** The critical point for a multicomponent mixture is referred to as the state of pressure and temperature at which all intensive properties of the gas and liquid phases are equal (point C). At the critical point, the corresponding pressure and temperature are called the critical pressure p_c and critical temperature T_c of the mixture.
- **Phase envelope (two-phase region):** The region enclosed by the bubble-point curve and the dew-point curve (line BCA), wherein gas and liquid coexist in equilibrium, is identified as the phase envelope of the hydrocarbon system.
- **Quality lines:** The dashed lines within the phase diagram are called quality lines. They describe the pressure and temperature conditions for equal

volumes of liquids. Note that the quality lines converge at the critical point (point C).

- **Bubble-point curve:** The bubble-point curve (line BC) is defined as the line separating the liquid-phase region from the two-phase region.
- **Dew-point curve:** The dew-point curve (line AC) is defined as the Line separating the vapor-phase region from the two-phase region. In general, reservoirs are conveniently classified on the basis of the location of the point representing the initial reservoir pressure p_i and temperature T with respect to the pressure-temperature diagram of the reservoir fluid. Accordingly, reservoirs can be classified into basically two types. These are:
 - **Oil reservoirs:** If the reservoir temperature T is less than the critical temperature T_c of the reservoir fluid, the reservoir is classified as an oil reservoir.
 - **Gas reservoirs:** If the reservoir temperature is greater than the critical temperature of the hydrocarbon fluid, the reservoir is considered a gas reservoir. (Tarek Ahmed, 2001)

2.4. Oil Reservoirs

Depending upon initial reservoir pressure p_i , oil reservoirs can be sub classified into the following categories:

A) Undersaturated oil reservoir

If the initial reservoir pressure is greater than the bubble-point pressure p_b of the reservoir fluid, the reservoir is labeled an undersaturated oil reservoir.

B) Saturated oil reservoir

When the initial reservoir pressure is equal to the bubble-point pressure of the reservoir fluid, the reservoir is called a saturated oil reservoir.

C) Gas-cap reservoir

If the initial reservoir pressure is below the bubble point pressure of the reservoir fluid, the reservoir is termed a gas-cap or two-phase reservoir, in which the gas or vapor phase is underlain by an oil phase. The appropriate quality line gives the ratio of the gas-cap volume to reservoir oil volume. Crude oils cover a wide range in

physical properties and chemical compositions, and it is often important to be able to group them into broad categories of related oil,(Tarek Ahmed, 2001)

2.5. Identification of Fluid Type

Reservoir fluid type can be confirmed only by observation in the laboratory. Yet; readily available production information usually will indicate the type of fluid in the reservoir. Rules of thumb will be given for identification of each of the five fluid types.

Three properties are readily available: the initial producing gas-oil ratio, the gravity of the stock-tank liquid, and the color of the stock-tank liquid. Initial producing gas-oil ratio is by far the most important indicator of fluid type. The color of stock-tank liquid alone is not a good indicator of fluid type. However, stock-tank liquid gravity and color are useful in confirming the fluid type indicated by the producing gas-oil ratio.

If all three indicators-initial gas-oil ratio, stock-tank liquid gravity, and stock-tank liquid color-do not fit within the ranges given in the rules of thumb, the rules fail and the reservoir fluid must be observed in the laboratory to determine its type.

Do not attempt to compare fluid types as defined here with the reservoir descriptions as defined by the state regulatory agencies which have jurisdiction over the petroleum industry. The legal and regulatory definitions of oil, crude oil, gas, natural gas, condensate, etc., usually do not bear any relationship to the engineering definitions given here. In fact, the regulatory definitions are often contradictor ,(WILLIAM D.McCAIN, 1990)

2.6. Classification of reservoir fluid

2.6.1. Ordinary black oil

A typical pressure-temperature phase diagram for ordinary black oil is shown in Figure 2-2. It should be noted that quality lines which are approximately equally spaced characterize this black oil phase diagram. Following the pressure reduction path as indicated by the vertical line EF on Figure 2-2, the liquid shrinkage curve, as shown in Figure 2-3, is prepared by plotting the liquid volume percent as a function of pressure. The liquid shrinkage curve approximates a straight line except at very low

pressures. When produced, ordinary black oils usually yield gas-oil ratios between 200–700 SCF/STB and oil gravities of 15 to 40 API. The stock tank oil is usually brown to dark green in color.

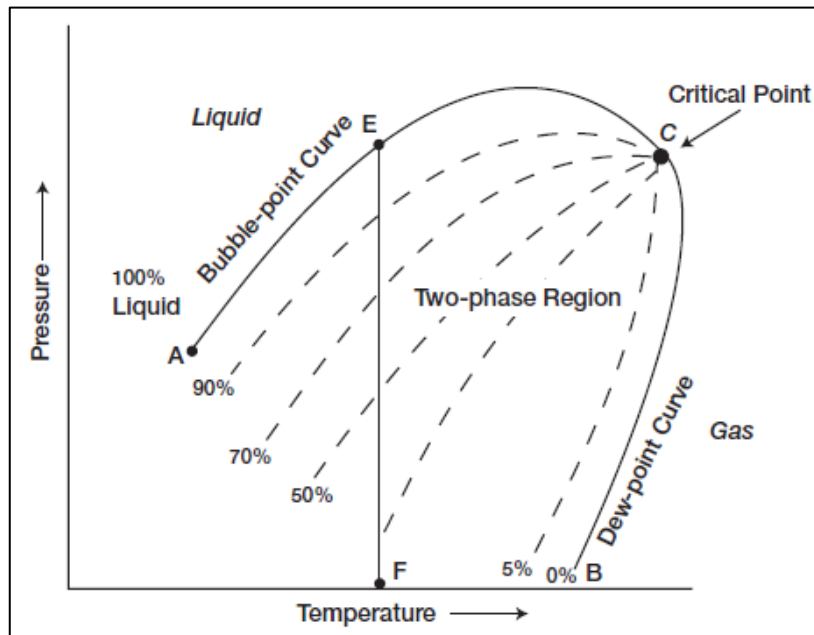


Figure 2-2 : Pressure-temperature diagram for an ordinary black oil, (Tarek Ahmed, 2001)

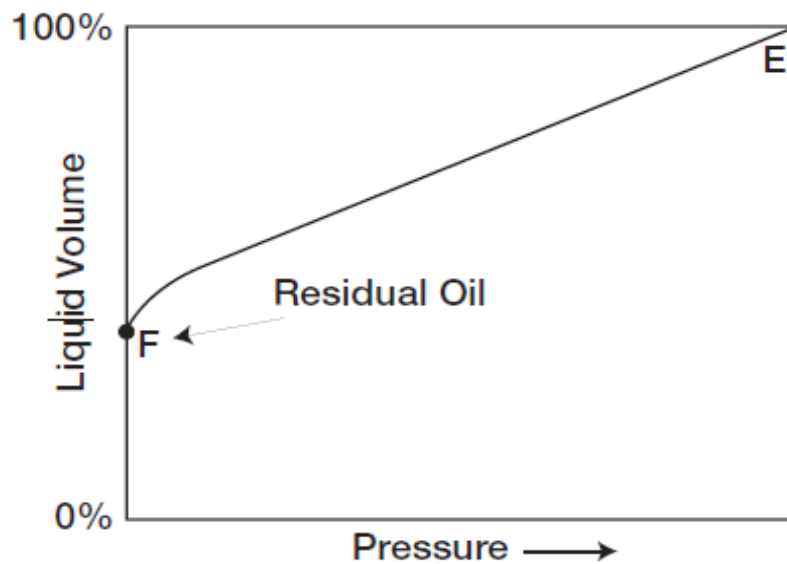


Figure 2-3: Liquid-shrinkage curve for black oil, (Tarek Ahmed, 2001)

2.6.2. Low-shrinkage oil

A typical pressure-temperature phase diagram for low-shrinkage oil is shown in Figure 2-4. The diagram is characterized by quality lines that are closely spaced near the dew-point curve. The liquid-shrinkage curve, as given in Figure 2-5, shows the shrinkage characteristics of this category of crude oils. The other associated properties of this type of crude oil are:

- Oil formation volume factor less than 1.2 bbl/STB
- Gas-oil ratio less than 200 SCF/STB
- Oil gravity less than 35° API
- Black or deeply colored

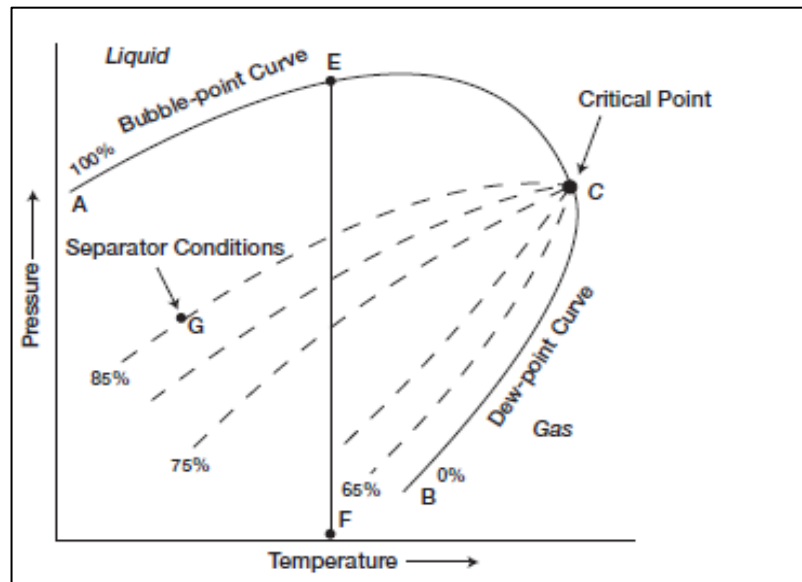


Figure 2-4: phase diagram for a low-shrinkage oil,(Tarek Ahmed, 2001)

- Substantial liquid recovery at separator conditions as indicated by point G on the 85% quality line of Figure 2-4.

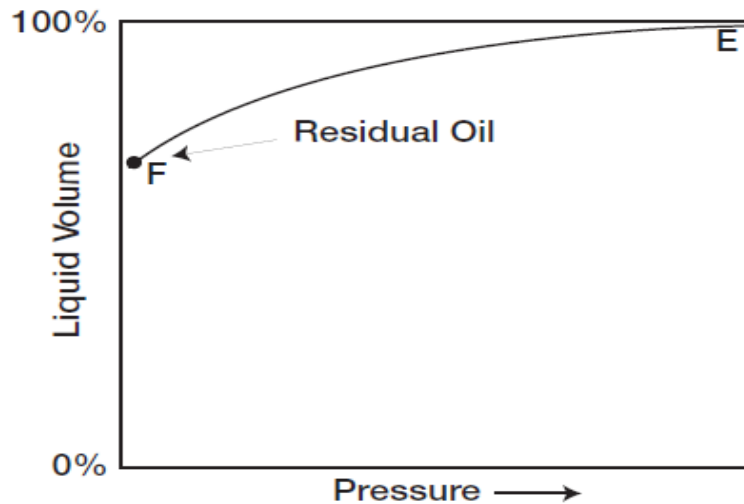


Figure 2-5: Oil-shrinkage curve for low-shrinkage oil, (Tarek Ahmed, 2001)

2.6.3. High-shrinkage (volatile) crude oil

The phase diagram for a volatile (high-shrinkage) crude oil is given in Figure 2-6. Note that the quality lines are close together near the bubble-point and are more widely spaced at lower pressures.

This type of crude oil is commonly characterized by a high liquid shrinkage immediately below the bubble-point as shown in Figure 2-7. The other characteristic properties of this oil include:

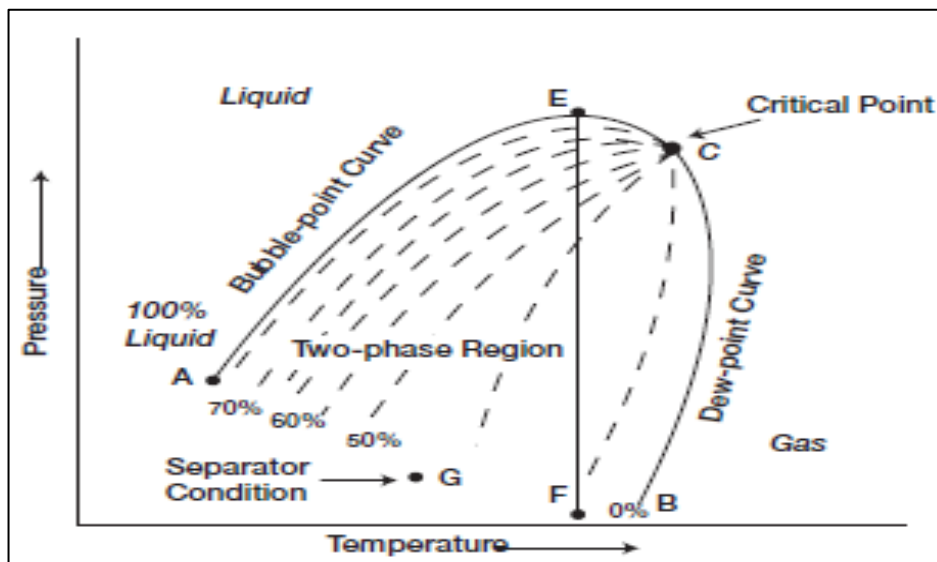


Figure 2-6: pressure-temperature diagram for a volatile crude oil, (Tarek Ahmed, 2001)

- Oil formation volume factor less than 2 bbl/STB
- Gas-oil ratios between 2,000–3,200 SCF/STB

- Oil gravities between 45–55° API
- Lower liquid recovery of separator conditions as indicated by point G on Figure 2-6.

- Greenish to orange in color

Another characteristic of volatile oil reservoirs is that the API gravity of the stock-tank liquid

will increase in the later life of the reservoirs.

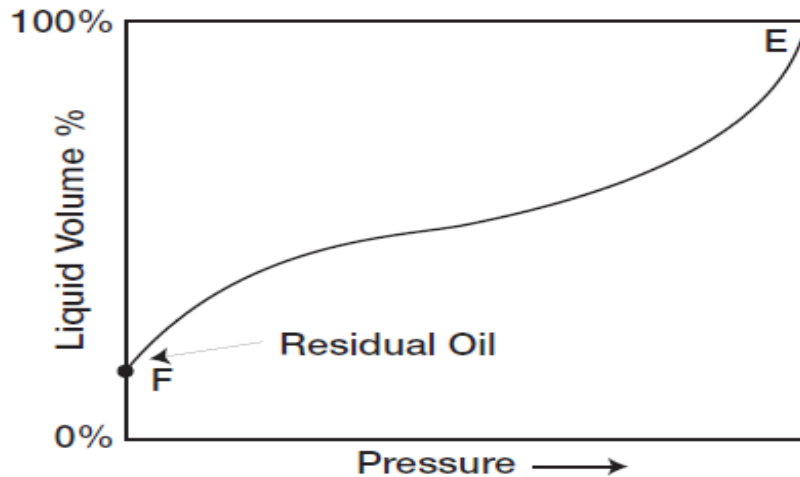


Figure 2-7: A typical liquid-shrinkage curve for a volatile crude oil, (Tarek Ahmed, 2001)

2.6.4. Near-critical crude oil

If the reservoir temperature T is near the critical temperature T_c of the hydrocarbon system, as shown in Figure 2-8, the hydrocarbon mixture is identified as a near-critical crude oil. Because all the quality lines converge at the critical point, an isothermal pressure drop (as shown by the vertical line EF in Figure 2-8) may shrink the crude oil from 100% of the hydrocarbon pore volume at the bubble-point to 55% or less at a pressure 10 to 50 psi below the bubble point. The shrinkage characteristic behavior of the near-critical crude oil is shown in Figure 3-9. The near-critical crude oil is characterized by a high GOR in excess of 3,000 scf/STB with an oil formation volume factor of 2.0 bbl/STB or higher. The compositions of near-critical oils are usually characterized by 12.5 to 20 mol% heptanes-plus, 35% or more of ethane through hexanes, and the remainder methane.

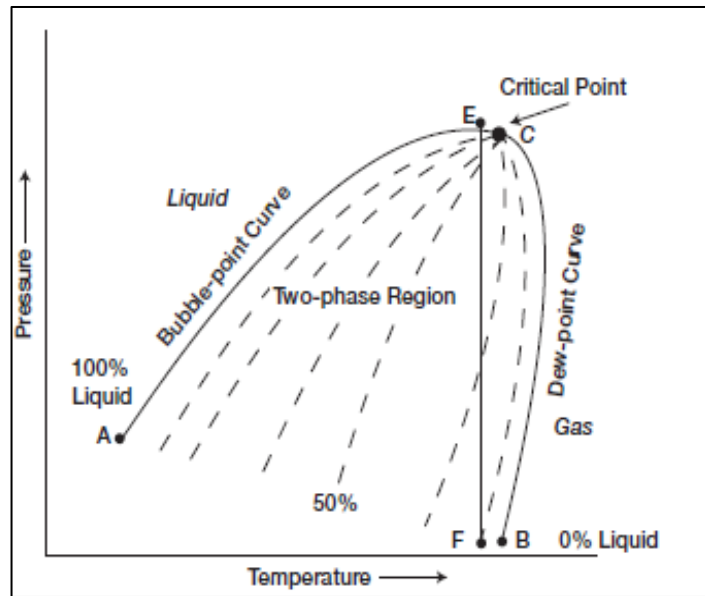


Figure 2-8: phase diagram for the near-critical crude oil, (Tarek Ahmed, 2001)

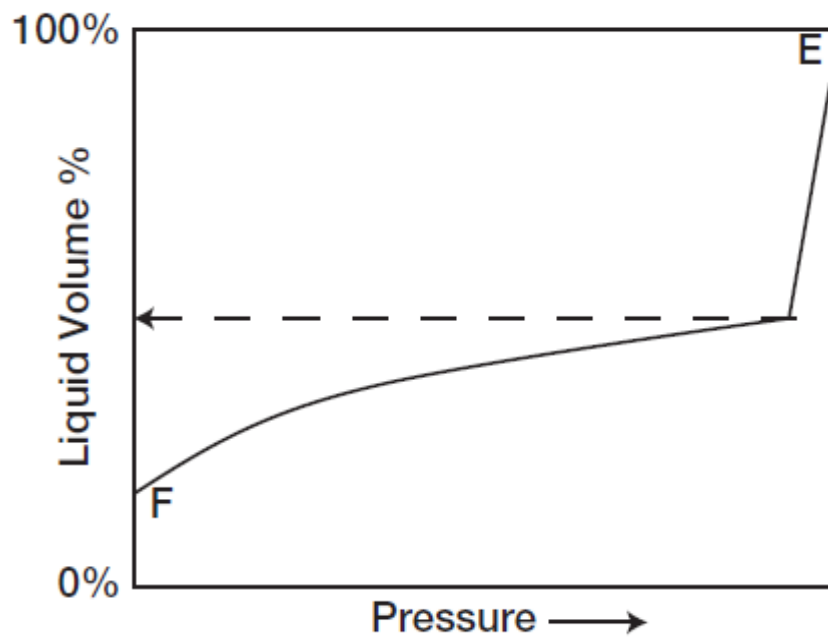


Figure 2-9: a typical liquid-shrinkage curve for the near-critical crude oil, (Tarek Ahmed, 2001)

2.7. Laboratory Analysis of Reservoir Fluids

The main laboratory analysis which are used in determination of reservoir fluids properties are:

2.7.1. Constant-Composition Expansion Tests

Constant-composition expansion experiments are performed on gas condensates or crude oil to simulate the pressure-volume relations of these hydrocarbon systems. The test is conducted for the purposes of determining:

- Saturation pressure (bubble-point or dew-point pressure).
- Isothermal compressibility coefficients of the single-phase fluid in excess of saturation pressure.
- Compressibility factors of the gas phase.
- Total hydrocarbon volume as a function of pressure, (Tarek Ahmed, 2001)

The experimental procedure, as shown schematically in Figure 2-10 involves placing a hydrocarbon fluid sample (oil or gas) in a visual PVT cell at reservoir temperature and at a pressure in excess of the initial reservoir pressure, the pressure is reduced in steps at constant temperature by removing mercury from the cell, and the change in the total hydrocarbon volume V_t is measured for each pressure increment.

The saturation pressure (bubble-point or dew-point pressure) and the corresponding volume are observed and recorded and used as a reference volume V_{sat} .

The volume of the hydrocarbon system as a function of the cell pressure is reported as the ratio of the reference volume. This volume is termed the relative volume and is expressed, mathematically by the following equation:

$$V_{rel} = \frac{V_t}{V_{sat}} \quad (2 - 1)$$

Where:

V_{rel} = relative volume

V_t = total hydrocarbon volume

V_{sat} = volume at the saturation pressure

The relative volume is equal to one at the saturation pressure. This test is commonly called pressure-volume relations, flash liberation, flash vaporization, or flash expansion.

It should be noted that no hydrocarbon material is removed from the cell, thus, the composition of the total hydrocarbon mixture in the cell remains fixed at the original composition.

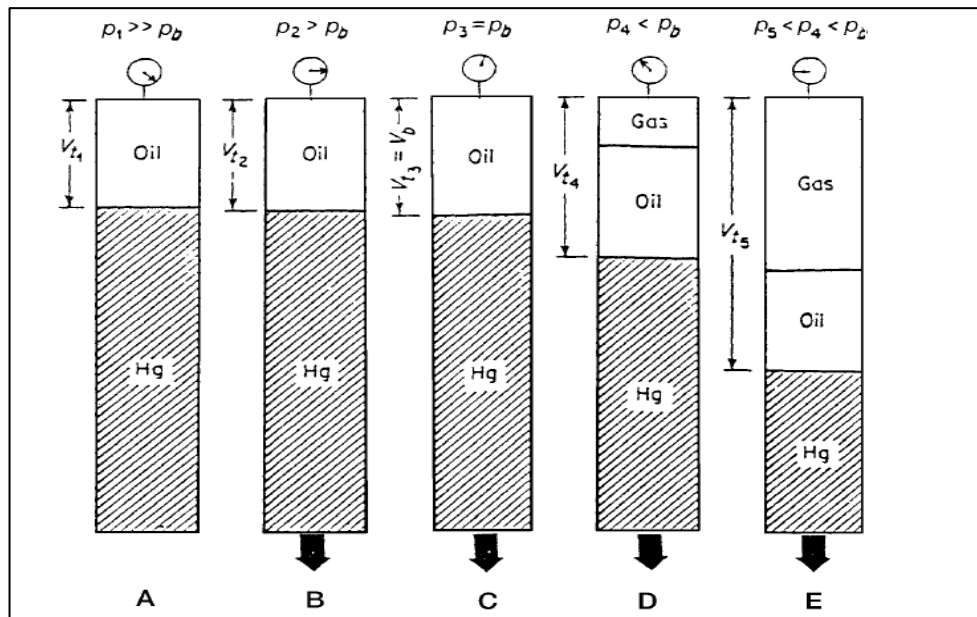


Figure 2-10: Constant-composition expansion test,(Tarek Ahmed, 2001)

The density of the oil can be calculated by using the recorded relative volume:

$$\rho = \frac{\rho_{sat}}{V_{rel}} \quad (2-2)$$

Where:

ρ = density at any pressure above the saturation pressure

ρ_{sat} = density at the saturation pressure

V_{rel} = relative volume at the pressure of interest

The relative volume data frequently require smoothing to correct for laboratory inaccuracies in measuring the total hydrocarbon volume just below the saturation pressure and also at lower pressures. A dimensionless compressibility function, commonly called the **Y-function**, is used to smooth the values of the relative volume. The function in its mathematical form is only defined below the saturation pressure and is given by the following expression:

$$Y = \frac{(P_{\text{sat}} - P)}{P(V_{\text{ref}} - 1)} \quad (2 - 3)$$

Where:

P_{sat} = saturation pressure, psia

p = pressure, psia

V_{rel} = relative volume at pressure p

2.7.2. Differential Vaporisation

When the reservoir pressure falls below the bubble point the process of gas liquid separation in the reservoir is one of a constant changing system. A PVT process has been designed in an attempt to provide a means of in part simulating the changing systems as separation occurs within the reservoir below the bubble point.

The differential vaporisation differs from the flash in that the liberated gas is removed from the cell stepwise. At each step below the bubble point the quantity of gas, oil volume, density, gas expansion and gas compressibility are determined.

The objectives of the differential test therefore are to generate PVT data for conditions below the bubble point. Figure 2-12 below indicates the differential process.

The bubble point P_b is the starting pressure for the differential test.

The next step is to reduce the pressure in the PV cell by expansion of the PV cell volume. The reduction of pressure causes the system to go two phase. All the gas phase is removed at constant pressure by reducing the cell volume as gas is withdrawn. The volume of the remaining oil is then determined. The cell pressure is then again dropped by expansion of the PV cell and the above process repeated until the cell pressure has been dropped to atmospheric pressure. The pressure steps for the tests cover a range of around 8-10 steps.

All the above steps have taken place at reservoir temperature. The final stage is to reduce the cell to 60°F keeping the pressure at atmospheric pressure. The final oil volume is measured. This remaining all is termed residual oil to distinguish it from stock tank oil which although at the same pressure and temperature conditions has got there by a different process. The cumulative weight of the amounts of gas withdrawn is used in the calculation of the densities of the oil phase in the differential vaporisation process. These densities can also be determined directly if a pressure pycnometer is available. Differential liberation is considered to be representative of

the gas-liquid separation process in the reservoir below the bubble point pressure. Flash liberation is considered to take place between the reservoir and through the separator.

Differential liberation tests are carried out therefore to obtain oil formation volume factors and GOR's that can be used to predict the behaviour of a reservoir when the pressure has dropped below the bubble point pressure, (Heriot-Watt University, 2005)

The experimental data obtained from the test include:

- Amount of gas in solution as a function of pressure
- The shrinkage in the oil volume as a function of pressure
- Properties of the evolved gas including the composition of the liberated gas, the gas compressibility factor, and the gas specific gravity
- Density of the remaining oil as a function of pressure (Tarek Ahmed, 2001)

2.7.3. Separator test

The objective of these tests is to examine the influence of separator pressure and temperature on formation volume factor, gas/oil ratio, gas density and tank-oil density. These tests are not driven by those who will be responsible for the optimized separation process if the field ultimately is developed. They are carried out to give an indication of the oil shrinkage and GOR which occurs when the fluids are produced to surface conditions. It should be emphasized at this stage that there is not a unique value for the formation volume factor and solution gas-oil ratio. It depends on the stages and conditions of separation through which the fluids pass with the equipment available, a single test or a multiple separation test can be carried out.

The procedure for the separation test is as follows. The starting point is oil in the PVT cell at its reservoir bubble point, ie. the same starting condition as the differential test. Fluid is displaced from the PVT cell ensuring that the PVT cell contents remain at bubble point pressure. The gas and liquids are collected from the separation stage(s) and their respective properties measured. The final stage is at stock tank conditions. the resulting fluid is termed stock tank oil.

A single separator test is carried out by flashing reservoir liquid at bubble point pressure and reservoir temperature through the separator operating at the average annual temperature and at pressures which may be expected in the field. The

difference in results when using a single or a double separator is that in the former case the total gas/oil ratio is higher, the shrinkage is greater and the density of the tank oil is higher than in the latter case.

The main objectives of the separator test are in combination with the flash vaporisation and differential tests to provide formation volume factor and solution gas-oil ratios over a full pressure range above and below the bubble point. In quoting these values it is important to recognise that the values are separator condition specific.(Heriot-Watt University, 2005)

2.8. Artificial Neural Network (ANN)

2.8.1. Introduction

In biological definition, Natural neurons receive signals through synapses located on the dendrites or membrane of the neuron. When the signals received are strong enough (surpass a certain threshold), the neuron is activated and emits a signal through the axon. This signal might be sent to another synapse, and might activate other neurons.

Artificial neural network is that technology initially grew from the full understanding of some ideas and aspects about how biological systems work, especially the human brain.

Inspires neural network systems is drawn from many disciplines: primarily from neuroscience; engineering, and computer science; but also from psychology, mathematics, and physics stems are typically organized in layers.

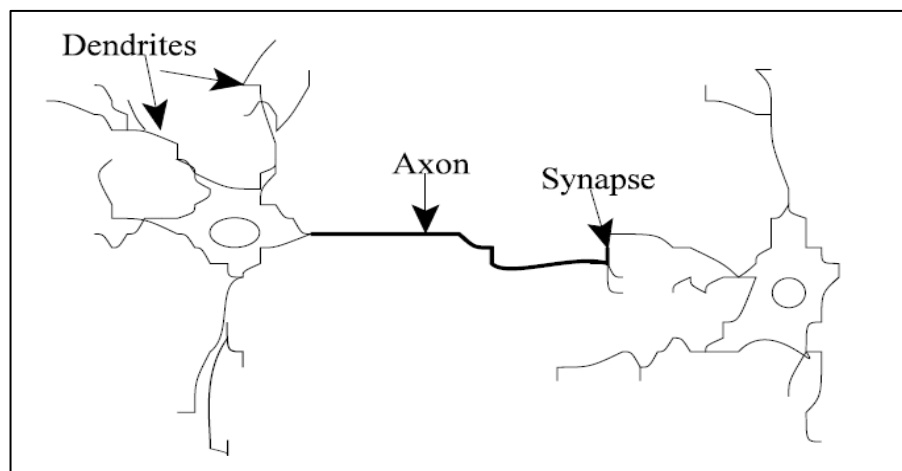


Figure 2-11: Biological neurons, (Rojas, March 1996)

2.8.2. Computing definition

The simplest definition of a neural network, more properly referred to as an 'artificial' neural network (ANN), is provided by the inventor of one of the first neuro computers, Dr. Robert Hecht-Nielsen. He defines a neural network as:

"a computing system made up of a number of simple, highly interconnected processing elements, which process information by their dynamic state response to external inputs", (Rojas, March 1996)

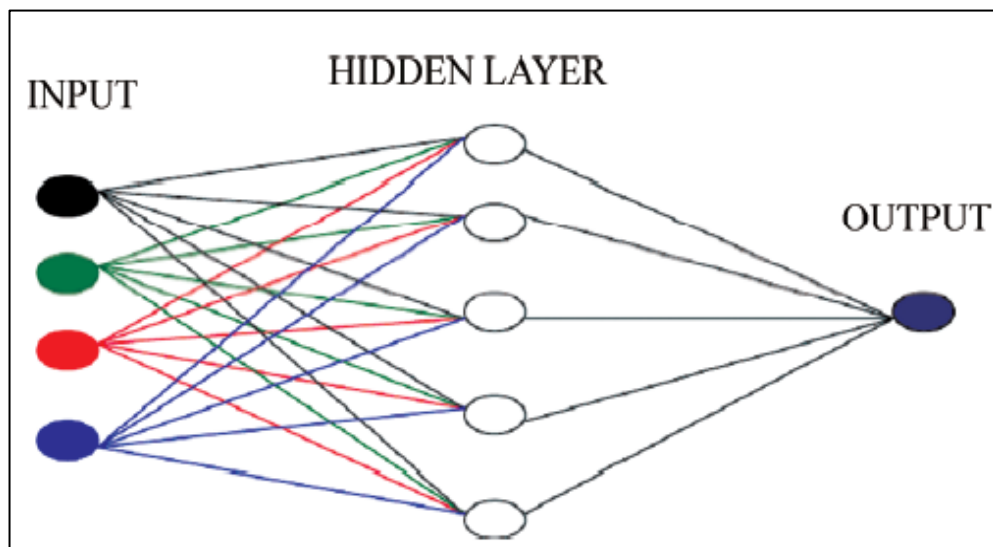


Figure 2-12: Structure of artificial neural network of present study, (Azubuiké, 2013)

2.8.3. Applications of artificial neural network

- | | |
|------------------------|----------------------------------|
| 1- Aerospace | 2- Automotive |
| 3- Banking | 4- Credit Card Activity Checking |
| 5- Defense | 6- Electronics |
| 7- Entertainment | 8- Financial |
| 9- Industrial | 10- Insurance |
| 11- Oil & Gas industry | 12- Robotic |

2.8.4. Polynomial Neural Network (PNN)

The Polynomial Neural Network (PNN) algorithm is also known as International Algorithm of Group Methods of Data Handling (GMDH). GMDH were originally proposed by Prof. A.G. Ivakhnenko. PNN correlates input and target

variables using (non) linear regression. In this particular software the user can define the desired properties of the solution such as the **number** of terms and the maximum **degree** of polynomials using an approach proposed by Prof. Yu.P.Yurachkovsky, (Ladislav Zjavka, 2011)

2.9. Bubble Point Pressure Studies over the World

Standing (1947) used 105 experimentally measured bubble-point pressures on 22 hydrocarbon systems from California oil fields, he proposed a graphical correlation for determining the bubble-point pressure of crude oil systems, the correlating parameters in the proposed correlation are the gas solubility, gas gravity, oil API gravity, and the system temperature. The reported average error is 4.8%.

After that Vasquez and Beggs (1980) estimate bubble point pressure. The correlation was developed from 600 laboratory PVT analyses from fields all over the world. The correlation divided the data into two groups based on oil gravity, then after that a 45 oil samples were used by Glaso, mostly from the North Sea hydrocarbon system, to develop an accurate correlation for bubble-point pressure prediction.

Marhoun's (1985) consist of equations for estimating bubble Point Pressure, solution gas-oil ratio and oil formation volume factor for Saudi Arabian oil, seventy five bottom hole fluid samples from 62 reservoirs in Saudi Arabia were used in the development of these correlations, another study by him was in (1988), a 160 experimentally were used in determining bubble-point pressures from the PVT analysis of 69 Middle Eastern hydrocarbon mixtures to develop a correlation for estimating pb by Marhoun, The author correlated the bubble-point pressure with the gas solubility R_s , temperature T , and specific gravity of the oil and the gas.

Then came petrosky-farshed (1993) and used nonlinear multiple regression software to develop a gas solubility correlation. the authors constructor a PVT database from 81 laboratories analyses from Gulf of Mexico crude oil system.

Another study was done by (Hanafy et.al 1997) consists of equations for estimating bubble point pressure, solution gas-oil ratio, and oil formation volume factor and oil compressibility, oil density and oil viscosity for Egyptian crude oil, this study evaluates the accuracy of the empirically derived PVT correlations relative to the experimental PVT for 324 Egyptian oil samples taken from 123 reservoirs in 75 fields. the tested Correlations are used to estimate the bubblepoint pressure, oil

formation volume factor, isothermal oil compressibility, oil density, and oil viscosity. Before measuring the accuracy of different correlations, it should be pointed out that the effective use of the correlations lies in an understanding of their development and knowledge of their limitations

(Gharbi et.al, 1997) published two papers to develop ANN models to predict oil PVT properties. the first paper uses the neural system to estimate the P_b and B_o for Middle East crude oil reservoirs.

both network was trained using 498 Middle East data sets and tested with unseen 22 data,

The second was developed by them, for estimating P_b and B_o , this model was developed using three-layer neural network model and 5200 data sets collected from all over the world representing 350 different crude oils, another set of data consisting of 234 data sets was used for verifying the results of the model, the reported results for the universal model showed less improvement than the Middle East neural model over the conventional correlations.

As personally study to (Elsharkawy, 1998) he presented a new technique to model the behaviour of crude oil and natural gas systems using a radial basis function neural network model RBFNM, the model can predict oil formation volume factor, solution gas-oil ratio oil viscosity, saturated oil density, undersaturated oil compressibility, and evolved gas gravity, He used differential PVT data of ninety samples for training and another ten novel samples for testing the model. Input data to the RBFNM were reservoir pressure, temperature, stock tank oil gravity, and separator gas gravity, accuracy of the model in predicting the solution gas oil ratio, oil formation volume factor, oil viscosity, oil density, undersaturated oil compressibility and evolved gas gravity was compared for training and testing samples to all published correlations, the comparison showed that the proposed model is much more accurate than these correlations in predicting the properties of the oils, the behaviour of the model in capturing the physical trend of the PVT data was also checked against experimentally measured PVT properties of the test samples. he concluded that although, the model was developed for specific crude oil and gas system, the idea of using neural network to model behaviour of reservoir fluid can be extended to other crude oil and gas systems as a substitute to PVT correlations that were developed by conventional regression techniques,

After that the artificial neural network technique ANN is becoming more common, and the evidence is that, another study was done by (Sarit et.al ,2009) for Indian crude West Coast, they used artificial neural network ANN as learning machine to develop correlation for bubble point , also they used Baysain regularization technique and prevent over fitting and also he used genetic as algorithm to obtain optimum network weights, as result this new correlation provided the lower values of average absolute relative error for bubble point pressure. the relative error of this correlation 7.668%, the other absolute error around 15%.

Then Nada S. Ahmedzeki et.al (2012) presented artificial neural network ANN model for predicting the bubble point pressure for oil fields in Iraq. the most affecting parameters were used as the input layer to the network, those were reservoir temperature, oil gravity, solution gas-oil ratio and gas relative density, the model was developed using 104 real data points collected from Iraqi reservoirs, the data was divided into two groups, the first was used to train the ANN model, and the second was used to test the model to evaluate their accuracy and trend stability, trend test was performed to ensure that the developed model would follow the physical laws. Results showed that the developed model outperforms the published correlations in term of absolute average percent relative error of 6.5%, and correlation coefficient of 96%.

After one year, Wirit Cuptasantia et.al, (2013) were using neural network to predict bubble point pressure and bubble point oil formation volume factor, the data sets were screened for redundant data, each data set was selected randomly and divided into developing, and test data sets. Nonlinear regression was the technique used to develop each correlation. for ANN development, the developing data sets were randomly divided into training, validation, and testing sets, different network architectures and transfer functions were used for developing the best ANN model, after numerous trails on nonlinear regression technique in Minitab software using the developing datasets, the P_b correlation was developed by modifying Calhoun's correlation, the correlation coefficient was 0.93179, and average absolute error was 21.32%.

Another nice study, Afoama Ebuka Godwin et.al, (2014) developed new predictive models for P_b and Bob based on Generalized Regression Neural Network GRNN a form of Artificial Neural Network ANN using field data collected from Niger Delta reservoirs and compare it with existing empirical correlations and a Back

Propagation Neural Network BPNN model, the data are divided into three groups, The first one 196 sets was used to train the GRNN models, the second group 49 sets was used to cross-validate the training, and the last group 24 sets was used to test the models to evaluate their accuracy and trend stability, the correlation coefficient for GRNN was 0.977, and for BPNN was 0.954.