Reservoir Engineering

Reservoir engineering grew out of the recognition that recovery from oil and gas reservoirs could be predictable and actually could be increased if made more the reservoirs were analyzed and managed.

Oil and gas accumulate in underground traps formed by structural and/or stratigraphic features. Usually occur in the more porous and permeable beds, which are sands, sandstones, limestones and dolomites in the intergranular openings, or in pore spaces.

What is a reservoir?
It is that portion of a trap which contains of Oil and/or gas as a single ~~hydrocarbon~~ hydraulically connected system.

Many reservoirs are connected to various volumes of water-bearing rock called aquifers.

Under initial reservoir conditions, the hydrocarbon fluids are in a single-phase or two-phase state. Single-phase may be a liquid phase (oil) in which all the gas present is dissolved in the oil.
∴ there are dissolved gas and crude oil reserves to be estimated. How?

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The Single-phase may be a natural gas phase.

* "If there are hydrocarbons vaporized in this gas phase that are recoverable as natural gas liquids on the surface, the reservoir is called gas-condensate."

Primary Recovery

* When there is no aquifer and no fluid is injected into the reservoir, the recovery is brought about by fluid expansion.

* When there is water influx from the aquifer, or when water is injected into selected wells, recovery is accomplished by displacement mechanism.

* Gas is injected as a displacing fluid to help in the recovery of oil and is also used in gas cycling to recover gas-condensate

* The use of natural gas or a water injection schemes is called a "secondary recovery operation".

When water injection is used as a secondary recovery process, this process is called "water flooding".

* Other displacement processes called "Tertiary recovery" processes have been developed in application when secondary recovery precosses have been ineffective

Tasks of Reservoir Engineers:

The tasks of reservoir engineers are centered around answering the following questions:

* How much oil and gas is originally in place?
* What the drive mechanisms for the reservoirs?
* What are trapping mechanisms for the reservoir?
* What will the recovery factor be for the reservoir by primary depletion?
* What will future production rates from the reservoir be?
* How can the recovery be increased economically?
* What data are needed to answer these questions?

* Two methods are available to determine OOIP: Volumetric method; and MB method.
* The MBE and various drive indices can be calculated to give an indication of the relative strength of different drive mechanisms
* The displacement theories of Buckley Leverett and Tarner can be used to forecast future recovery and production rates.

* How to increase recovery from a reservoir:
  By water flooding
  Steam flooding
  Miscible gas flooding
  Polymer flooding — and Surfactant flooding are also used

Data Sources:—

To determine OOIP — the data needed are: ϕ, h, fluid saturation (S_o, S_w, + S_g) and FVF + GVF, fluid thermal compressibilities

these are From logs + Cores

bottom hole sample of reservoir fluids

To use MBE — the data are the P/V relationships of res. fluids, and the production volumes of oil, water, and gas as a function of reservoir pressure.

Fundamental Drive Mechanisms

The res. engineer needs to know and understand by what mechanism the oil is being produced.

$P_i > P_b$ → * Solution-gas and fluid expansion drive

* Gas-Cap drive — $P_i = P_b$ @ GOC

* Water drive —

* Gravity drive, and —

* Combination drive.

Reservoir Types Defined With Reference to Phase Diagram (P-T)

Various types of reservoirs can be defined by location of the initial reservoir pressure and temp. with respect to the two-phase (gas + liquid) region as shown on P-T phase diagram of a reservoir fluid.

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Reservoir Types Defined with Reference to Phase Diagram

From a technical point of view, the various types of reservoirs can be defined by the location of the initial reservoir temperature and pressure with respect to the two-phase (gas and liquid) region as commonly show on P-T phase diagram.

See the attached figure 1 is the P-T phase diagram of a particular reservoir fluid.

The area enclosed by the bubble pt. and dew pt. lines to the lower left is the region of pressure and temperature combinations in which both gas and liquid phases will exist.

The curves within the two-phase region show the percentage of the total hydrocarbon volume that is liquid for any temp. and pressure.

Consider a reservoir containing the fluid of the attached figure 1 initially at 300°F and 3700 psia, Point A. Since this point lies outside the tw-phase region, it is originally in a one-phase state, commonly called gas as located at point A.
Since the fluid remaining in the reservoir during production remains at 300°F, it will remain in the single-phase or gaseous state as the pressure declines along path AA_1.

Furthermore, the composition of the produced well fluid will not change as the reservoir is depleted. This is true for any accumulation of this composition where the reservoir temp. exceeds the cricondentherm, or max. two-phase temp. (250°F for the present example).

Although the fluid left in the reservoir remains in one phase, the fluid produced thru the wellbone and into surface seperators, although the same composition, may enter the two-phase region owing to the temp. decline, as along line AA_2. This accounts for the production of condensate liquid at the surface from a gas in the reservoir.

Of course, if the cricondentherm of a fluid is below 50°F, then only gas will exist on the surface at usual ambient temperatures and the production will be called dry gas.

Next, Consider a reservoir containing the same fluid of the attached figure, but at a temperature of 180°F and an initial pressure of 3300 psia, Point B. Here the fluid also initially in one-phase state, called gas, where the reservoir temp. exceeds the critical temp. As the pressure declines because of production, the composition of the produced fluid will be the same as for reservoir A and will remain constant until the dew-point pressure is reached 2700 psig, point B_1. Below this pressure a liquid condenses out of the reservoir fluid as a fog or dew, and this type of reservoir is called a dew-point reservoir.

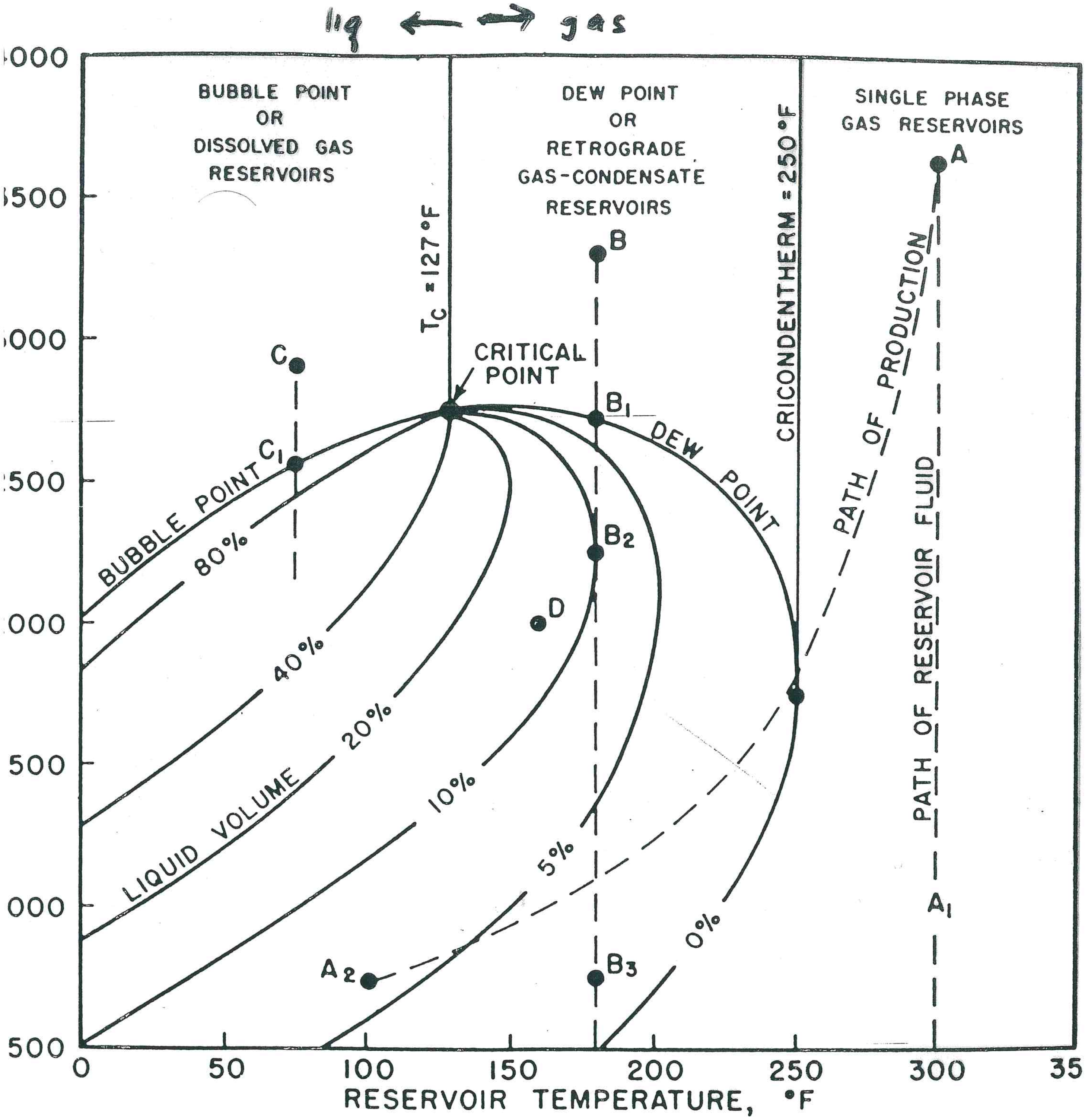
This condensation leaves the gas phase with a lower liquid content. Because the condensed liquid adheres to the walls of the pore spaces of the rock, it is immobile. thus the gas produced at the surface will have a lower liquid content, and the producing gas-oil ratio therefore rises. this process of retrograde condensation continues until a point of max. liquid volume is reached, 10% at 2250 psia, Point B_2. "the term retrograde is used because generally vaporization, rather than condensation, occurs during isothermal expansion."

For qualitative purposes vaporization of retrograde liquid occurs from B_2 to the abandonment pressure B_3. this vaporization aids liquid recovery and may be evidenced by decreasing gas-oil ratios on the surface.

If the accumulation occured at 2900 psia and 75 °F, Point C, the reservoir be in one-phase state, liquid, because the temp. is below the critical temp.

Finally, if this same hydrocarbon mixture occured at 2000 psia and 150°F, point D, it would be a two-phase reservoir, consisting of liquid (oil) zone overlain by a gas zone or Cap.

voir Types Defined with Reference to Phase Diagrams



Pressure-temperature phase diagram of a reservoir fluid

Table I

Characteristics of Various Driving Mechanisms

	Characteristics				
Mechanisms	Reservoir Pressure	GOR	Water Production	Recovery Efficiency	Others
1. Solution gas drive	Declines rapidly and continuously	First low, then rises to maximum and then drops.	None (except in high S_w reservoirs)	5-35% Avg.-20%	Requires pumping at an early stage.
2. Gas cap drive	Falls slowly and continuously.	Rises continuously in up-dip wells.	Absent or negligible.	20-40% Avg.-25% (Can be detrimental to oil prod.)	Gas breakthrough at a down-dip well indicates a gas cap drive.
3. Water drive	Remains high. Pressure is sensitive to the rate of oil, gas and water production.	Remains low if pressure remains high.	Down-dip wells produce water early and water production increases to appreciable amount.	35-80% (rare) Avg.-50% (for better fields)	
4. Liquid and rock expansion	Declines rapidly and continuously. $p_i > p_b$	Remains low and constant.	None (except in high S_w reservoirs)	1-10% Avg.-3%	
5. Gravity drainage	Declines rapidly and continuously.	Remains low in down-dip wells and high in up-dip wells.	Absent or negligible.	40-80% Avg.-60%	When k > 200 md, formation dip > 10° and μ_o low (< 5 cp), + low well rates