

3 SAMPLING OF RESERVOIR FLUIDS

Samples of the reservoir fluid are usually collected at an early stage in the well's producing life and dispatched to a laboratory for the PVT analysis. The objectives of sampling are to receive samples from a suitable place in the production wells or surface facilities. The samples should represent the system in the reservoir under its initial conditions in order to determine its type, volumetric and phase behavior, and its composition. PVT analysis results are needed for geological and reservoir engineering evaluation and forecasting, as well as for laboratory studies concerning enhanced oil recovery (EOR).

There are basically three ways of collecting fluids samples from a well, either by Downhole Sampling, Wellhead Sampling or by Surface Recombination Sampling.

Representative Reservoir fluids should be sampled during drilling of exploration wells or as early as possible during the production life of a reservoir. When the reservoir pressure falls below the initial saturation pressure the hydrocarbon phase forms two phases of gas and liquid. The mole ratio of the two phases flowing into the well is not generally equal to that formed in the reservoir. Hence, the collection of a representative sample becomes a highly demanding, and in some cases an impossible task.

The sample can be collected either as a single phase at the bottom hole, when the pressure is still above the saturation value, or at the surface. The first reservoir fluid samples are collected during exploration drilling, as hydrocarbon sources are discovered. Bottom hole samples could be collected during open hole wire line operations, and formation testing, prior to production operations. Controlled Surface sampling is conducted on producing wells either at the well head, as a sample representing the producing mixture stream, or as Gas and Liquid samples out of a test separator at controlled conditions (production rate, pressure, temperature).

As long as the reservoir pressure has never been below its saturation pressure (P_s) for the reservoir fluid, and a single phase sample flows into the sampling bottle, the chance of collecting a representative sample is high. Producing fluids, however, are generally at two-phase conditions. Hence, the sampling procedure should aim at collecting the phases at such conditions where the subsequent recombination provides the original reservoir fluid. First, it should be ensured that representative fluids are flowing out of the formation, by properly conditioning the well before sampling. Next, fluid samples should be collected from all co-existing phases, and recombined at the producing ratio. Sampling from an oil reservoir, particularly an undersaturated one, is relatively a much simpler task than that from a gas condensate reservoir with very high GOR.

Production testing of reservoir zones was previous a standard test procedure. Information about reservoir productivity and pressure build up gave important information for reservoir characterization. During these operation, large quantities of reservoir fluid were produced, and large volumes of reservoir fluid could be sampled and stored for laboratory use.. Due to lack of infrastructure, produced fluid, especially gas, was burned. Today this represent an environmental issue, and production testing of reservoirs is reduced to a minimum.

3.1 Bottom hole sampling

Bottom hole samplers are specially designed devices containing one valve or two valves at their extreme ends. They are run in the hole, on wireline, to the reservoir depth and the sample collected from the subsurface well stream at the prevailing bottom hole pressure. The valves are either mechanically or electrically operated to be close and trap a volume of the borehole fluids in the sampling chamber.

Once at the surface, the sample should immediately be transferred to containers through a flexible steel tube. This steel tube is filled up with an inert liquid, generally with mercury, together with the shipping bottle. This can be done using a mercury injection pump.

Subsurface sampling method will obviously yield a representative fluid sample of the reservoir giving that the oil is undersaturated with gas to such a degree that the bottom hole flowing pressure P_{wf} at which the sample is collected, is above the bubble point pressure.

If the reservoir was initially at bubble point pressure P_b or suspected of being so, the subsurface sample should then be collected with the well still closed in.

If the reservoir is known to be initially undersaturated the sample can be collected with the well flowing at a very low rate so that the P_{wf} is still above P_b .

3.1.1 Formation testing

Early stage formation fluid sampling could be performed today in open hole. Service companies offering wire line operations for geological and petrophysical data collections. During these operations, formation testing tools could provide several bottom hole reservoir fluid samples in small volumes (~500 ml) together with important reservoir data, as described in Fig. 3.1.

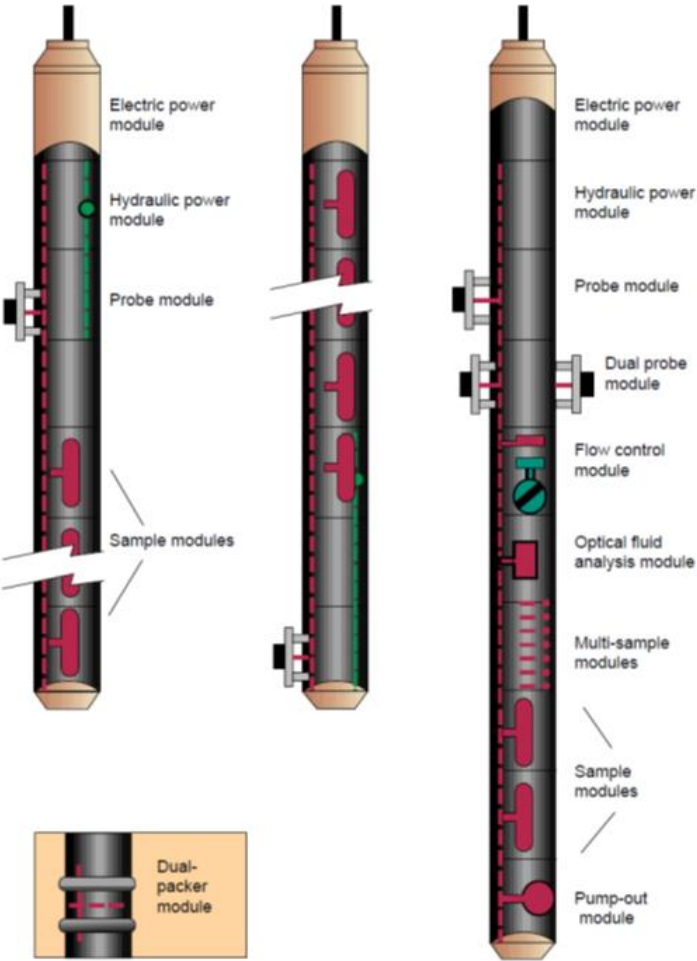


Fig. 3.1: The modular design of the MDT tools enables engineers to select the modules

A standard MDT setup includes single probe module with a combinable Quartz Gauge and variable pre-test chamber for fast and accurate pressure measurements, and multiple sample chambers.

The optional modules provide permeability anisotropy, mini DST (drillstem test), sampling and fluid identification capabilities.

The MDT –tool (Modular Formation Dynamics Tester) from Schlumberger provides:

- Filtrate pumpout prior to sampling

- Fluid resistivity and temperature measurements at the probe
- Quantitative sample contamination measurement (optical spectroscopy techniques)
- Formation fluid sampling (multi sample collection (~500 ml) in one operation)
- Permeability and anisotropy measurement
- Mini-drill stem test (DST) and productivity assessment
- Formation pressure measurement
- fluid contact identification
- In-situ stress and minifrac testing

Fig. 3.2 and Fig. 3.3 gives examples of reservoir data obtained from MDT measurements in addition to bottom hole fluid samples.

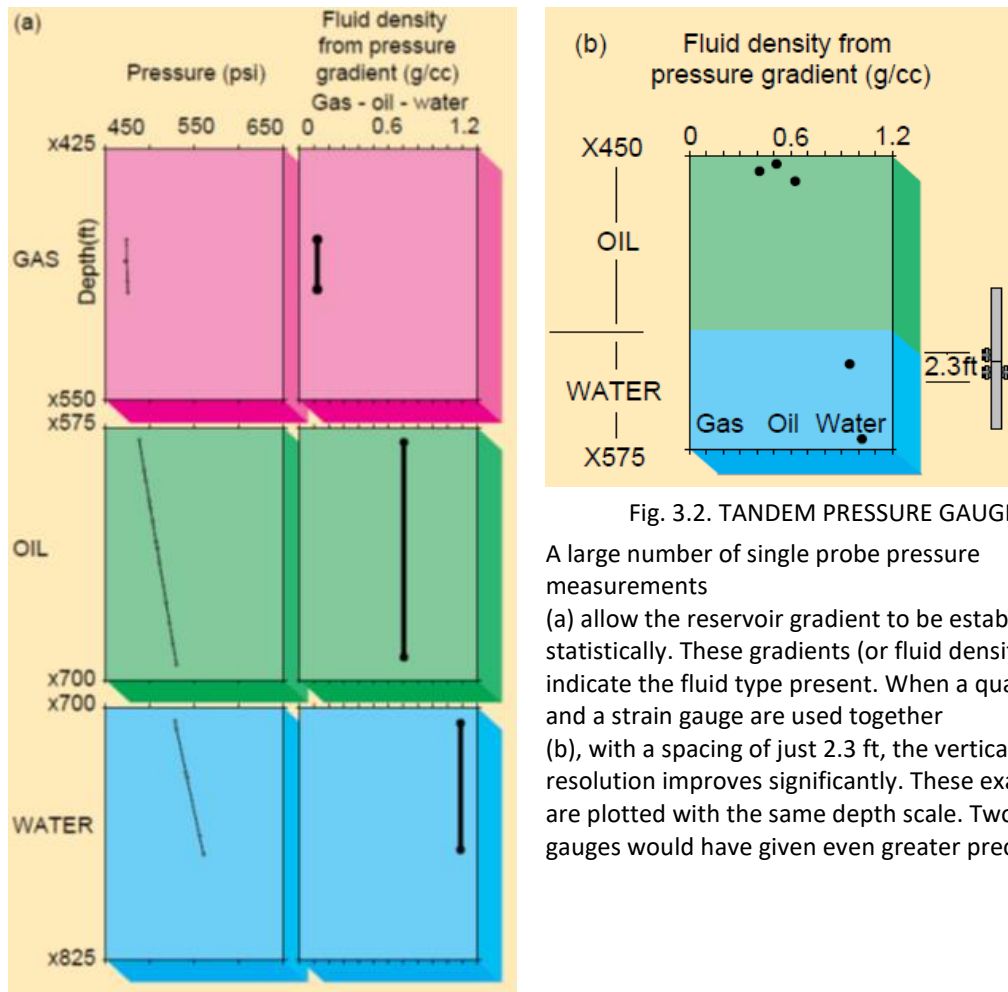


Fig. 3.2. TANDEM PRESSURE GAUGES:

A large number of single probe pressure measurements (a) allow the reservoir gradient to be established statistically. These gradients (or fluid density) indicate the fluid type present. When a quartz gauge and a strain gauge are used together (b), with a spacing of just 2.3 ft, the vertical resolution improves significantly. These examples are plotted with the same depth scale. Two quartz gauges would have given even greater precision.

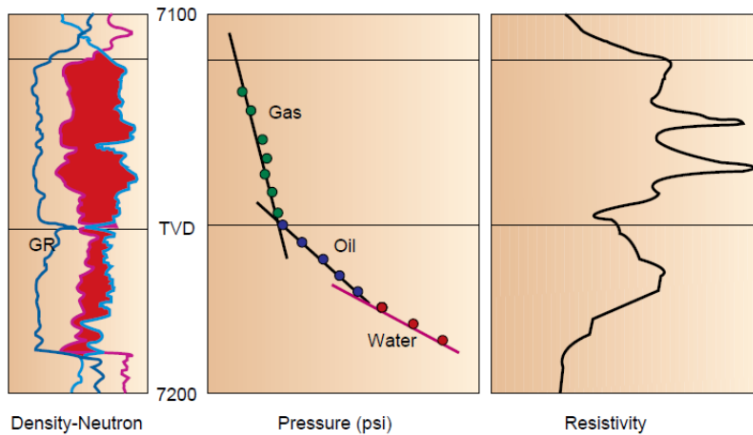


Fig. 3.3: FLUID FINDER:
Formation pressures can be used to define fluid type at any given depth within the reservoir and to locate fluid contacts.

3.2 Drillstem test (DST)

Well tests conducted with the drill string still in the hole. Often referred to as DST, these tests are usually conducted with a downhole shut-in tool that allows the well to be opened and closed at the bottom of the hole with a surface-actuated valve. One or more pressure gauges are customarily mounted into the DST tool and are read and interpreted after the test is completed.

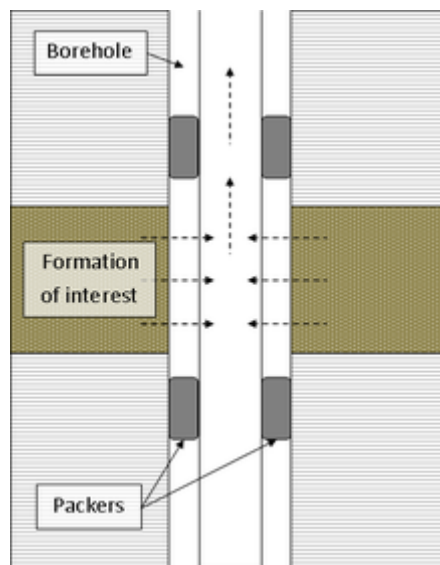


Fig. 3.4 Drillstem test (DST) and test separator at surface for fluid sample collection.

The tool includes a surface-actuated packer that can isolate the formation from the annulus between the drillstring and the open hole/casing, thereby forcing any produced fluids to enter only the drillstring. By closing in the well at the bottom, afterflow is minimized and analysis is simplified, especially for formations with low flow rates. The drillstring is sometimes filled with an inert gas, usually nitrogen, for these tests. With low-permeability formations, or where the production is mostly water and the formation pressure is too low to lift water to the surface, surface production may never be observed. In these cases, the volume of fluids produced into the drillstring is calculated and an analysis can be made without obtaining surface production. Occasionally, operators may wish to avoid surface production entirely for safety or environmental reasons, and produce only that amount that can be contained in the drillstring. This is accomplished by closing the surface valve when the bottomhole valve is opened. These tests are called closed-chamber tests.

Drillstem tests are typically performed on exploration wells, and are often the key to determining whether a well has found a commercial hydrocarbon reservoir. The formation often is not cased prior to these tests, and the contents of the reservoir are frequently unknown at this point, so obtaining fluid samples is usually a major consideration. Also, pressure is at its highest point, and the reservoir fluids may contain hydrogen sulfide, so these tests can carry considerable risk for rig personnel. The most common test sequence consists of a short flow period, perhaps five or ten minutes, followed by a buildup period of about an hour that is used to determine initial reservoir pressure. This is followed by a flow period of 4 to 24 hours to establish stable flow to the surface, if possible, and followed by the final shut-in or buildup test that is used to determine permeability, thickness and flow potential.

3.3 Surface sampling

In reservoir fluid sampling, if the well bottom hole pressure has fallen below the oil bubble point, the well is generally conditioned by a period of reduced flow, followed by a shut-in period of about 1-3 days. This lowers the pressure draw-down and raises the oil pressure, possibly above its original bubble point. The method is not suitable for a gas condensate reservoir. The pressure build-up may vaporize the condensed liquid in the reservoir into the gas phase to form a gas condensate even richer than the original fluid. Unless, the condensation was limited only within a small zone around the wellbore, allowing the disposal of the richer gas over a reasonable period of conditioning, the collected sample will not be representative.

The formation of condensate initiates around the wellbore, where the pressure is at its lowest value in the reservoir, Fig. 3.5. The two-phase region gradually grows into the reservoir bulk as the pressure declines during production. As the depletion rate is low, the advancement of the two-phase region is slow. Hence, it is reasonable to assume a quasi-steady-state condition around the producer, with minimal changes over a short period. At such conditions, the overall composition of the gas-condensate mixture flowing into the wellbore is the same as that flowing into the two-phase region, as no condensate accumulation occurs in that region. Hence the reservoir outflow, if collected properly, should represent the original single phase reservoir fluid.

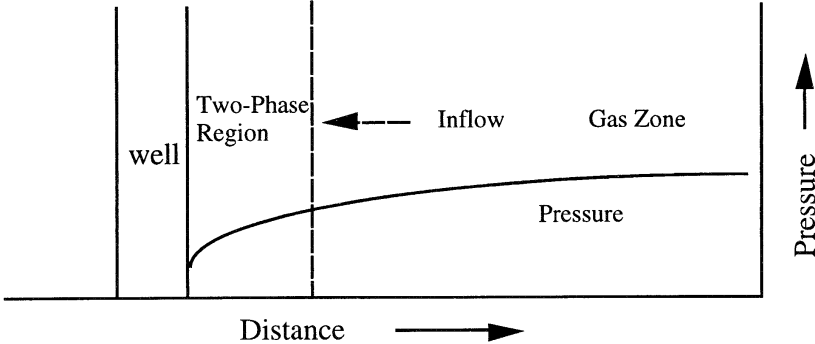


Fig. 3.5. Schematic diagram of two-phase flow around wellbore for a gas condensate fluid.

The validity of the above assumption, can be evaluated by numerical simulation of the flow near the wellbore using a compositional model [6]. Sudden changes of rate will disturb the steady state conditions and the outflow composition. It is advisable, therefore, to maintain the rate prior to sampling.

Producing the gas at a low rate to maintain the bottom hole pressure above the dew point can ensure the flow of single phase gas into the wellbore. It is imperative, however, that the well flow rate remains above a minimum value for the continual up-lifting of the condensate formed within the wellbore.

The liquid phase is transferred up the well partly as entrained drops in the gas core, and partly as a film on the wall by the gas shearing effect (annular-mist flow). The transfer of liquid between the film and droplets is a continuous process along the liquid path up the well. When the gas flow rate is reduced below a minimum value, the energy transferred to the liquid by the flowing gas may not be sufficient to carry the liquid. Then, the direction of liquid flow in the film is reversed and the entrained drops fall back, both resulting in well flooding. The minimum flow rate for continual removal of liquids (condensate or water) by the flowing gas can be determined by analyzing the film flow and the entrained drop movement. Turner et al. [7] developed a mechanistic two-phase flow model and applied it to the removal of liquid in a gas well. The authors compared the minimum gas velocity required to lift the entrained liquid with that for transferring the film upward and concluded that the former was the controlling limit.

The major forces which determine the velocity of a liquid drop are the downward gravity, and the upward gas drag. The gravity force is determined by the size of the drop and the liquid-gas density difference, whereas the drag force is dominated by the gas velocity and the physical properties of the two phases. An increase in the gas velocity increases the ratio of the drag force to the gravity force. Turner et al. balanced the two forces and derived the following relation for the minimum gas velocity to unload the well,

$$\overline{v_{g_m}} = 2.67\sigma^{1/4} \frac{(\rho_o - \rho_g)^{1/4}}{\rho_g^{1/2}} \quad (3.1)$$

where

$\overline{v_{g_m}}$ is the minimum gas velocity in m/s,

σ is the gas-condensate interfacial tension, mN/m,

ρ_o and ρ_g are the oil and gas density, kg/m³,

all at the well head conditions.

Turner et al.[7] used the following average values in the above equation,

Condensate density :	721 kg/m ³ (45 lb/ft ³)
Gas-condensate interfacial tension:	20 mN/m
Gas specific gravity:	0.6
Gas temperature:	322 K (120°F)

and proposed the following equation,

$$\overline{v_{g_m}} = 1.49 \left(\frac{100 - P}{P^2} \right)^{1/4} \quad (3.2)$$

where

P is the wellhead pressure in MPa.

The minimum gas velocity can be converted to the gas production rate, knowing the tubing inside diameter and estimating the gas compressibility factor.

3.2.1 Test separator

Surface samples are commonly collected from test separators. A typical surface separator system at a production unit with a test separator for collecting production samples from the individual well streams is shown in Fig. 3.6.

The oil (condensate) and gas samples must be collected as single phase fluids. The principle of a test separator is presented in Fig. 3.7.

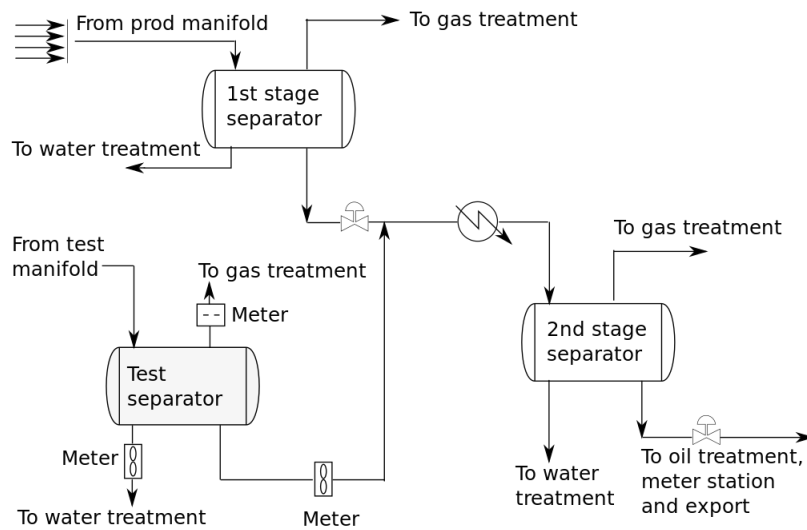


Fig. 3.6. Production separator system with Test Separator

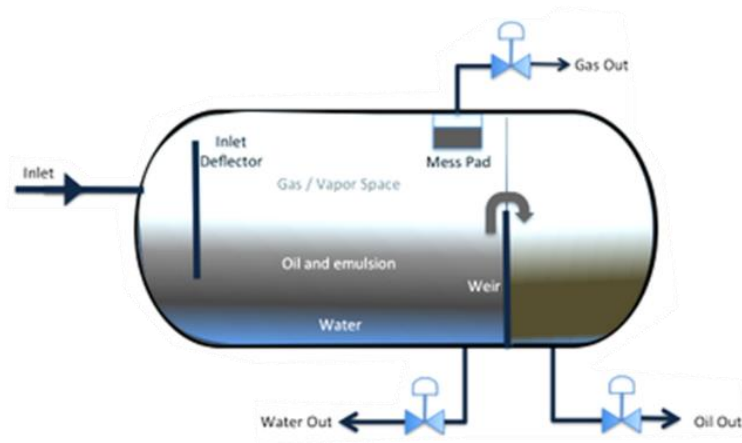


Fig. 3.7. The principle of a Test separator

A typical test separator unit with the separator unit equipped with with valves, liquid level control and metering units for gas, oil and water production at the wellsite is shown in fig. 3.8:



Fig. 3.8. Test separator unit at production site.

The production rate of each phase should be monitored over an extended period to ensure a steady and stable flow of both gas and liquid. Lower production rates will secure less fluctuations in gas and liquid rates. At stable production, the flow rates of gas and Liquid (Oil) from the separator are measured, and samples of produced gas and liquid (oil) is sampled in pressurized containers and shipped to laboratory for further analyses. fluid liquid

Based on the measured liquid rates gas and liquid at the test separator, a GOR_{rig} could be calculated:

$$GOR_{rig} = \frac{Q_{g(SC)}}{Q_{STO}} \quad (3.3)$$

Where

$Q_{g(SC)}$ – Gas metering rate at Standard Conditions (SC)

Q_{STO} – Liquid metering rate at standard conditions (SC)

GOR is always referred to Standard conditions (SC), and the flow rates at separator need to be corrected to standard conditions.

Gas rates at test separator:

Typical measuring devices for gas flow are shown in Fig. 3.9.

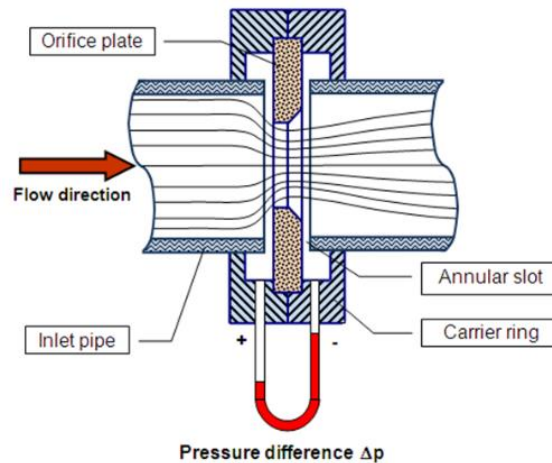


Fig. 3.9. Gas metering by Orifice.

The flow rate of gas using an orifice meter could be calculated:

$$Q_g = C \cdot \sqrt{H_w} \cdot P_f \quad (3.4)$$

where:

H_w – Differential pressure

P_f –dynamic pressure

and the metering constant C:

$$C = F_b \cdot F_g \cdot Y \cdot F_{tf} \cdot F_{PV} \cdot F_u \quad (3.5)$$

where:

F_b – orifice diameter

F_g –gravity factor

Y –expansion factor

F_{tf} – Temperature factor

F_{PV} – compressibility factor

F_u –Unit conversion factor

The gravity factor are calculated by :

$$F_g = \frac{1}{\sqrt{\gamma_g}} \quad (3.6)$$

$$(\gamma_g)_{rig} = \frac{m_g}{m_{air}} = \frac{\rho_g}{\rho_{air}} = \frac{M_g}{M_{air}} \quad (3.7)$$

where:

m – mass gas (g) or air

ρ – density of gas (g) or air

M – molecule weight of gas (g) or air

At the rig, the mass of gas and air could be measured by weight of a gas filled bulbs, Fig. 3.11.

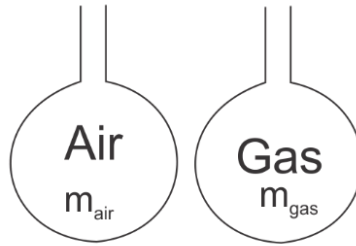


Fig.3.10. Gas filled bulb with fixed volume V_b for measuring the mass of a specific gas volume.

Compressibility factor F_{PV} :

$$F_{PV} = \frac{1}{\sqrt{Z_g}} \quad (3.8)$$

where Z_g is the deviation factor from the ideal gas law:

$$PV = Z_g nRT \quad (3.9)$$

When produced gas from the test separator is shipped to the laboratory, more correct values of gas gravity $(\gamma_g)_{lab}$ and gas compressibility $(Z_g)_{lab}$ could be obtained based on composition analyses of the gas, and are further used to correct the gas production rates and the separator gas oil ratio, $(GOR)_{corr}$, before fluid recombination in the laboratory.

Measuring liquid gas rate at test separator:

Rotameter is a typical measuring devices used for liquid flow measurements on a test separator, Fig. 3.1.

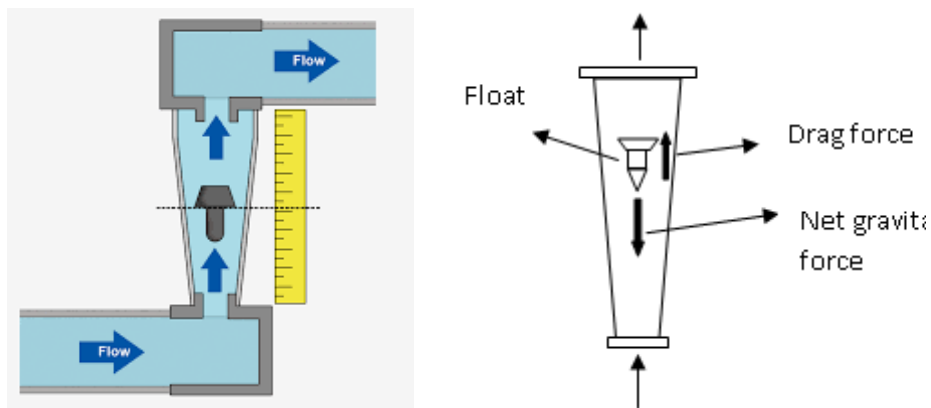


Fig. 3.11. Rotameter for liquid metering.

The rotameter measurements from the liquid oil production at test separator need to be corrected for contamination of Sediments and Water (BSW), and for shrinkage to Stock Tank conditions (STO) to represent oil volume at SC.

$$V_{STO} = (V_o)_{sep} \cdot F \cdot (1 - S_{hr}) \cdot K \cdot (1 - BSW) \tag{3.10}$$

Where:

- F -meter factor
- S_{hr} –shrinkage factor
- BSW – fraction of Basic sediment and Water

Volume Factor of oil (B_o) at separator conditions could be calculated :

$$B_o = \frac{(V_o)_{sep}}{(V_o)_{SC}} \tag{3.11}$$

And are used to describe the fluid shrinkage.

Separator Gas/Oil ratio:

When both gas rate $(Q_g/V_g)_{SC}$ and Oil rate $(Q_{STO}/V_{STO})_{SC}$ is verified, GOR at rig $((GOR)_{rig})$ is calculated and reported to the laboratory.

When composition analyses are performed on separator gas samples in the laboratory , more accurate gas gravity (γ_g) and gas compressibility factor (Z_g) could be calculated and the reported $(GOR)_{rig}$ could be corrected to $(GOR)_{corr}$ before fluid recombination og separator gas and separator liquid to reservoir fluid is performed.

$$(GOR)_{corr} = (GOR)_{rig} \cdot \sqrt{\frac{(\gamma_g \cdot Z_g)_{rig}}{(\gamma_g \cdot Z_g)_{lab}}} \tag{3.12}$$

The separator temperature and pressure, along with the producing gas/liquid volumetric ratio are reported to the PVT laboratory.

The information is used to evaluate the integrity of collected samples received in the laboratory, and to use in the recombination process, Fig. 3.12.

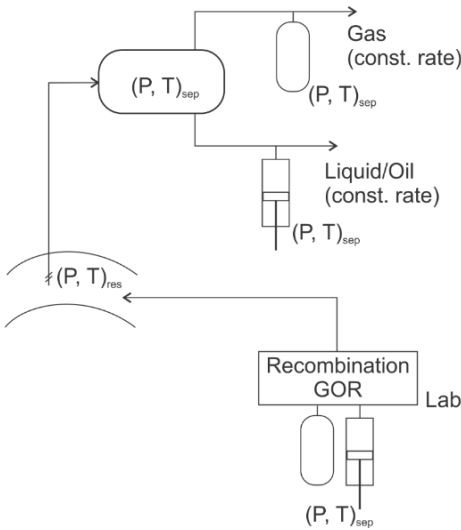


Fig. 3.12 Principle of separator test, with fluid sampling used for recombination to reservoir fluid.

3.2.2 Wellhead sampling

Sampling at the wellhead is a suitable process in case of the production of gas or undersaturated oil at wellhead conditions (wellhead pressure is greater than the dew point or bubble point pressure). This is typical for oils with low amount of dissolved gas (low GOR), or for dry and wet gasses.

With the produced reservoir fluid still is a one phase fluid at wellhead conditions (P_{wh} , T_{wh}), a representative reservoir fluid could be sampled at the wellhead, Fig. 3.13.

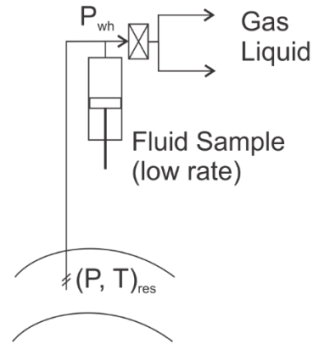


Fig. 3.13 Wellhead sampling at wellhead conditions (P_{wh} , T_{wh})

The sample cell is connected to a valve at the wellhead and flushed with the producing reservoir fluid.

3.2.3 Iso-kinetic surface sampling

The condensate carried over by gas in a separator can significantly distort the measured condensate to gas ratio. The effect can be serious for lean gas condensate systems.

An alternative surface sampling method is the collection of flowing phases in the tubing at the well head. A narrow tube, with the inlet facing the flow direction, is inserted in the center of the production tubing, Fig. 3.14.

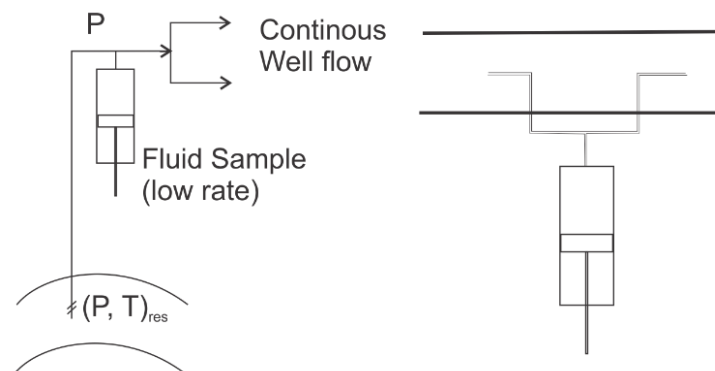


Fig. 3.14 Principle of iso-kinetic sampling for lean gas condensate fluids

A two-phase sample, consisting of the gas and entrained droplets, is collected through the narrow tubing into the sampling bottle. The sample flowing is collected with a fluid velocity in the tube equal to the average fluid velocity in the tubing. This is to avoid preferential collection of gas or condensate because of their different densities and momentum changes due to changes in the fluid velocity. The method, known as the iso-kinetic sampling [8], relies on the assumption that the condensate is

homogeneously distributed in the tubing flow. The homogeneity can be improved by inserting a mixing section ahead of the sampling tube.

3.4 Quality check of fluid samples

Before starting extensive laboratory analysis, it is important to evaluate the available fluid samples and to choose the sample thought to be the most representative for the reservoir hydrocarbon fluids.

3.5.1 Fluid samples from test separators.

Bottom hole reservoir fluid samples or Liquid and Gas samples obtained during the most stable separator conditions are normally chosen, Fig. 3.15.

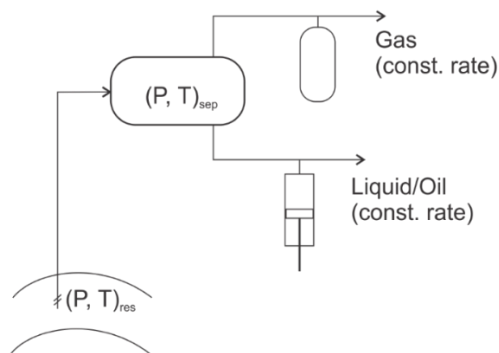


Fig.3.15 Test separator sampling of separator liquid and gas at P_{sep} and T_{sep} .

Samples received in the laboratory are evaluated for their integrity, primarily by measuring the opening pressure and comparing it with the reported sampling conditions. As the collected samples are saturated fluids, they often form two phases in the sampling bottle due to cooling. The pressure of collected liquid samples are often lowered purposely below the saturation pressure to form two phases for safety reasons, to avoid excessive pressure during transportation in case they are exposed to high temperature. Any leakage from a sampling bottle containing a gas-liquid mixture will change the sample composition. A lower opening pressure does not necessarily indicate a fluid loss, as it could be due to the thermal contraction. This may be examined by heating the bottle to the sampling temperature. A phase behavior model can also be used afterwards, when the fluid composition and PVT data are known, to estimate the expected opening pressure, and to adjust the fluid composition if a fluid loss was indicated [9].

3.4.1 Single-phase fluid samples

Quality check of single-phase fluid (liquid) samples are performed at sampling temperature.

The phase transition from one phase liquid to 2 phase gas and liquid could easily be seen in the laboratory as a change in the fluid compressibility. This test is performed on all single phase fluid (liquid) samples received in the laboratory to confirm the saturation point pressure, P_s , at sampling temperature, Fig. 3.11.

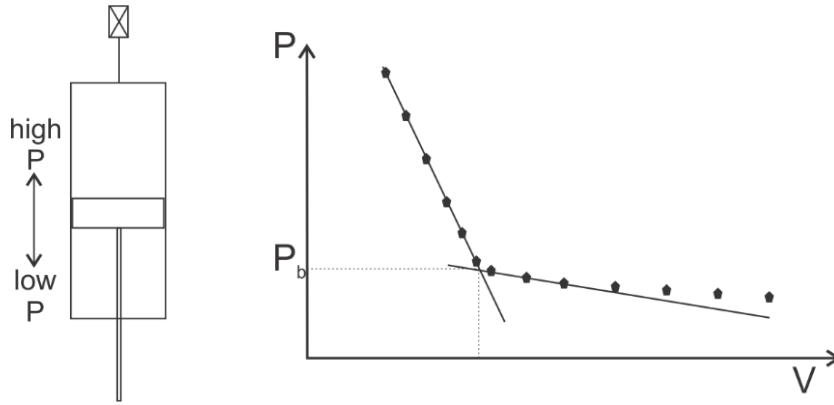


Fig. 3.16. Saturation point P_s (bubble point, P_b) measurements on fluid (liquid) samples.

Separator liquid samples should have a saturation pressure ($P_s = P_b$) close to P_{sep} , confirming correct sampling conditions and a representative separator liquid sample. All separator liquid samples used for further analyses in the laboratory should have similar saturation points (P_s).

Bottom hole samples with a $P_s < P_{wf}$ (P_{res}) indicates single phase reservoir fluid. For undersaturated fluids, the saturation point could be significant below reservoir pressure. Only bottom hole samples with similar saturation points (P_s) should be used in further laboratory experiments.

Further laboratory analyses of the fluid samples like chemical analyses, still could provide information that could be valuable for selecting the best fluid samples for recombination of reservoir fluids, or when phase behavior experiments are performed.

3.4.2 Gas samples

Gas samples collected at wellhead or test separators should be quality checked prior to use in laboratory experiments. The gas bottles should be heated to sampling conditions, T_{sep} or T_{wh} , and opening pressure should be similar for all chosen samples and close to the sampling pressure, P_{sep} or P_{wh} . Bottles with larger deviations should be excluded from further laboratory use, Fig. 3.17.

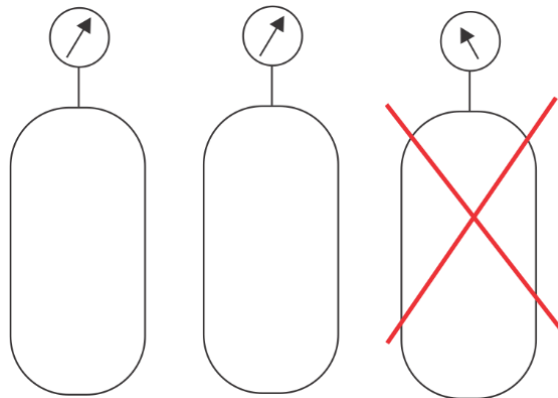


Fig. 3.17. Pressure test of Surface gas bottle samples heated to sampling conditions, T_{sep} or T_{wh} .

Further laboratory analyses of the gas samples, like chemical analyses, could provide valuable information for selecting the best fluid samples used in reservoir fluid recombination, and in phase behavior experiments.

3.5 Fluid recombination

Development plans for new reservoirs need reliable fluid property data, and optimized reservoir management need insight in fluid properties. This involves design and placement of production and injection wells and optimized fluid injection strategies for pressure maintenance and IOR/EOR.

The production facilities should be designed to handle the expected production volumes of Gas and Oil over the lifetime of the reservoir without the need severe modifications of the production unit which will require long term production shut off. Transport capacity for the produced oil and gas need also to be in place.

When the quality of reservoir fluid samples are acceptable, extensive fluid analyses could be performed in the laboratory to evaluate the properties of the reservoir fluid:

- Fluid recombination and composition analyses of recombined fluid
- PVT properties of reservoir fluid

3.5.1. Recombination of separator samples

Separator liquid and separator gas samples are recombined in the laboratory according to the reported gas/liquid ratio recorded in the field during sampling. When flow meters with coefficients depending on the fluid properties are used to measure the production rates, the reported ratio should be adjusted using the values measured in the laboratory, instead of the approximate data used in the field.

When the reservoir fluid is saturated and the compositional grading within the reservoir is minimal, the pressure-temperature at the gas oil contact identifies the saturation point. Hence, the measured saturation pressure of the recombined fluid should be compared with the field data.

For a recombined oil samples, a match between the two values indicates a representative sample. When the oil bubble point is known with confidence, it is advisable to adjust the recombination ratio to achieve it, instead of relying on the reported gas/liquid ratio. The recombined sample is expected to reasonably represent the reservoir oil, as the bubble point is sensitive to the gas/liquid ratio and increases with it.

A match between the measured dew point in the laboratory and the field reported value is desirable but does not necessarily indicate a representative gas sample. The dew point may increase or decrease by increasing the condensate/gas ratio, depending on the sample. Fig. 3.18 shows the liquid drop-out behavior of a North Sea gas condensate at the reservoir temperature prepared at different recombination ratios.

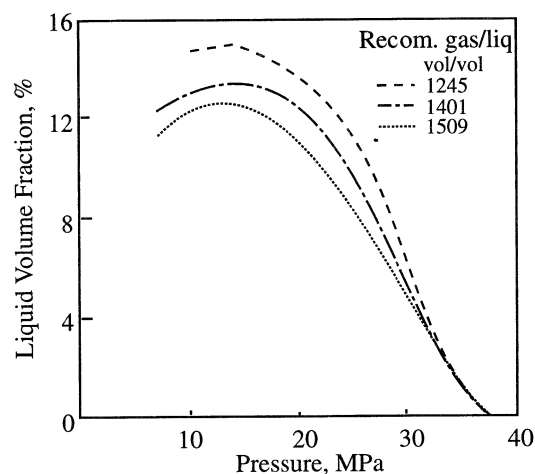


Fig. 3.18. Variations of condensate drop-out with adjusting recombination ratio.

Note the marked difference between the condensate drop-out behavior of different fluids, whilst their dew points are almost the same. It is quite evident that matching the dew point is not a reliable method for recombining a gas condensate sample.

3.5.2. Representative reservoir fluid samples?

Samples tested in PVT laboratories are fluids collected at the bottom hole or at the surface, and are not necessarily the same as those present within pores of a reservoir. Significant differences in composition between produced fluids and core extracts have been reported [10,11]. Core extracts often indicate a richer fluid in heavy fractions particularly surface active materials. This can be mostly due to the adsorption of polar compounds onto the core surface, which make them immobile during conventional sampling. The effect of adsorbed material on the multi-phase flow behavior of oil-water in pores is probably more significant than on the PVT properties in most cases. The samples collected from a flowing stream, however, may not be suitable for special phase behavior studies such as asphaltene deposition. A small amount of unrecovered adsorbed material is not expected to significantly change the saturation pressure and the gas-liquid volumetric fraction of an oil sample, but the effect on the gas condensate dew point may be very marked as its phase behavior is dominated by the concentration and properties of the heavy end.

When different samples are properly collected from the same reservoir, the samples are generally expected to be similar. In saturated reservoirs containing an oil column and a gas cap, the samples collected from each zone are expected to be reasonably in equilibrium with each other at the reservoir pressure and temperature. Compositional grading due to gravity and temperature gradient may however exist in a reservoir, with samples collected from different depths being vastly different. The compositional grading can be very severe, resulting in a column of fluid changing from a gas at the top to oil at the bottom, without any phase boundary. Phase behavior models can be used to evaluate the extent of compositional changes due to grading in order to evaluate the samples.

3.6 References

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