Understanding and Checking the Validity of PVT-Reports

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Introduction - The motivation for the lab work is that the knowledge of phase behavior and flow behavior is crucial for simulation of reservoir behavior and design of surface facilities and pipelines to the refinery. PVT experiments have been performed for decades. The need to review their accuracy, their evaluation together with consistency tests arises because of new equipment (mercury is banned in almost all labs). With the easy accessible oil being already produced, the complexity of the production process and the more extreme parameters of unconventional oil and gas demand a more sophisticated methodology in the experiments and an improved reporting. Quality control of the lab-data is therefore essential before using the numbers in the calculations. The specialization of the engineers asks for a detailed review of the methods and content of a PVT-report.

Sampling - The prime objective is to employ samples of the reservoir fluid in the experiments, that are identical (or close to) the reservoir fluid itself, usually labeled as a representative sample. Along with the sampling report a well test report helps to get insight into the sampling conditions and reservoir parameters. Circumstances to be observed are: firstly, an essential step in sampling one has to make sure that the well is already clean; secondly, samples should be taken from single phase streams; thirdly, taking samples at an early stage in the life of a reservoir is advisable. Later samples deviate from being representative.
Reservoir pressure is often a limiting factor in proper sampling. Saturated reservoirs or reservoirs close to saturation pressure pose a challenge, especially for low permeable formations. Where a pressure draw-down is needed for proper inflow, the fluid pressure may has dropped already locally below saturation pressure and hence into the two phase region from where in principle an original fluid sample cannot be obtained.
In case of a bottom-hole sample (BHS), mud or other fluids (or N2) used during drilling and completion may have entered the sample chamber. In order to proceed with the sample, the following procedure can be applied to get reasonable results from a contaminated sample:

- Perform the experiments with the contaminated material.
- Match the experiments with an equation of state (EOS). Basic rules are found in Whitson (2000), Whiston (1983), Whitson (1984)
- Analyze the contaminated sample.
- Analyze the oil based mud.
- Numerically decontaminate the sample from the mud numerically (find the most probable distribution of single carbon numbers).
- Recalculate the experiments with the decontaminated fluid and use the result as "real" properties for the reservoir fluid.

For that procedure a maximum contamination of 5 vol.% is suggested. Diesel as an oil based mud usually causes unwanted complications in determining the clean composition. Artificial mud, though more expensive, should be preferred because of a narrow distribution in the composition.
Separator samples (SS) are easier to collect and should always be taken as a backup for the BHS. In both cases, stable flow rates are essential. Separator should be large enough to avoid mist in the gas stream (carry-over) and gas in the liquid stream (carry-under). The phase envelopes of the separator gas and separator liquid should intersect at the separator conditions (p,T).

Sample transportation - In the laboratory, the opening pressures and temperature is recorded. A liquid container, for safety reasons, is always shipped with a gas cap. At separator temperature, the saturation pressure of the liquid sample should equal the separator pressure. In order to check whether a valve of the gas container leaked, the amount of gas at the sampling site and in the lab should be the same. For that purpose one checks it with the gas law. The calculation of the Z-factor requires the knowledge of the composition of the gas. In general, compositional analysis for all containers should be done. The analysis of the content of a BHS or a SS container requires a flash to ambient (laboratory) conditions. When recombining a gas and liquid phase pair of a SS, the collection of both samples at the same time should be ensured. Usually several pairs are collected. The selection of the most representative pair is often based on the oxygen content in the gas sample, which indicates air contamination of the sample. Actually, pairs of containers should be evaluated and then determined which of the recombined fluids is the most reliable.
Another check of the validity of pairs of SS can be carried out in the Hoffmann-plot in which the logarithm of the equilibrium or *K*-value is plotted versus the characterization factor *F* for every component (Whitson 2000).
It clearly reveals if some components have been detected with too low an amount in either phase. The sources of errors can be in the gas analysis with the higher components (points are too high) or with the lower carbon numbers, which may have already evaporated from the sample (points too low). The experimental *K*-factor can also be compared with the *K*-factor from Wilson's correlation (Whitson 2000).

Volumetric behavior of the reservoir fluid - Once a representative sample has been transferred to the PVT-cell, experiments are performed that mimic the flow in different stages for black oil and gas-condensate from the reservoir to the surface. All experiments are carried out at reservoir temperature. The abbreviations in the Figs. are CCE- Constant Composition Experiment, DLE – Differential Liberation Experiment and CVD – Constant Volume Depletion. The first experiment usually carried out is the CCE or sometimes also called the Constant Mass Experiment (CME).

Determination of the saturation pressure - The key to finding the saturation pressure is to use any function of pressure the first derivative of which is discontinuous in that point. The sought function is different for BO and GC.
For a BO the plot ln*Vt* (*Vt* is the total cell volume, oil and gas) versus p. Above the bubble point pressure the function is approximated by a straight line following the nature of a slightly compressible fluid. Its slope gives the oil compressibility. It is generally in the order of $O(10^{-3})$ MPa^{-1}.
A function that achieves the same goal for a GC is the function $p.V_t/Z_{1ph}$. It is proportional to the number of moles in the cell. The single phase real gas factor Z_{1ph} is calculated from the overall composition of the GC. Above the dew-point the function should be a straight horizontal line. In reality this is rarely the case. Firstly because the thermodynamic equilibrium might not have been reached in the cell and secondly because the correlation for the Z-factor has limited accuracy. Below the dew point the *Z*-factor is not correct. Therefore the curve departs from the straight line.
Other experiments are needed to mimic processes in the reservoir. The typical production path of a black oil reservoir is simulated by the differential liberation experiment (DLE) is the representative experiment. When the pressure drops below the bubble point, solution gas is liberated. While in reality it partitions into the gas cap and the well stream. In the DLE it is assumed that all the gas moves to the gas cap.
The experiment tailored for the production of a GC is based on the assumption that the volume of the reservoir is constant and from step to step a portion of the gas is removed.

Consistency checks for laboratory experiments - Textbooks contain a tool for checking the consistency of the BO CCE: The function $Y(p,p_b,V_t,V_b)$; *b* refers to the bubble point. It has no derivation based on thermodynamic principles, but nevertheless has proven itself to be useful. The Y-function works as well for the GC CCE. If V_t is set up properly, it can also applied to the BO DLE and GC CVD. For that purpose, the cumulatively liberated gas that is removed from the cell is added numerically at each pressure step to the oil (cell) volume.

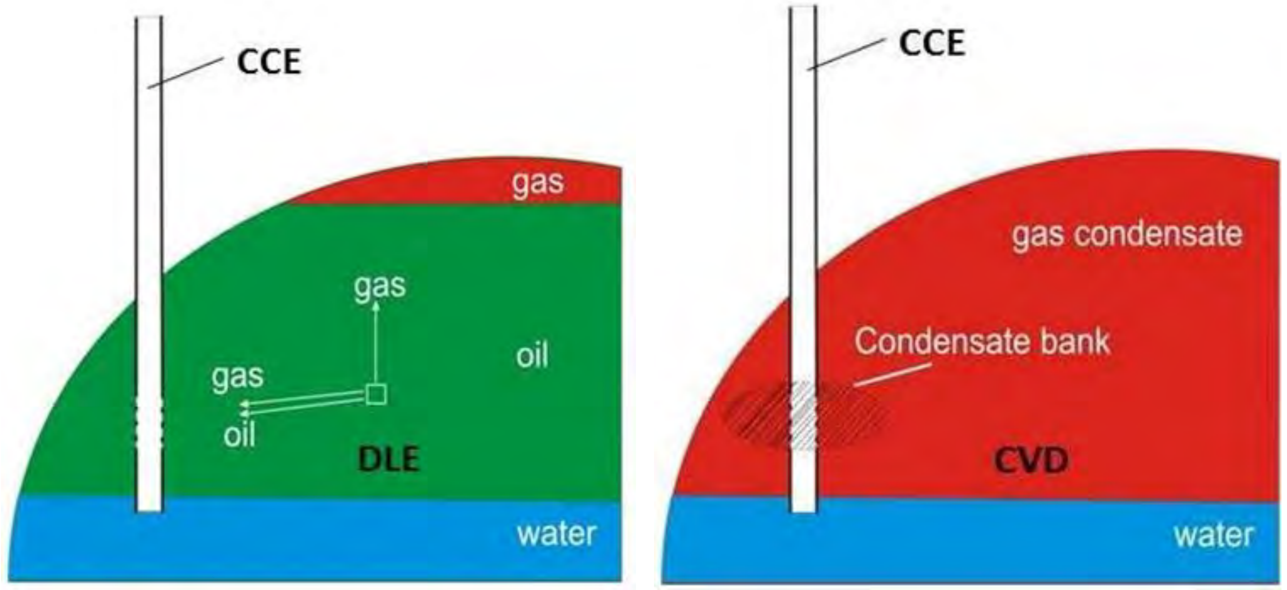
From the reservoir to the surface, BO - The fluid follows first a DLE inside the formation and then a CCE in the production string. In lab-experiments we see for the flash process (single step CCE) smaller values for B_o and R_s than in a DLE. This is the result of using different stock tank volumes (or densities) in the experiments.
The fluid undergoes in the reservoir blow the bubble point pressure a change that is characterized by the DLE curves (black lines) until it enters the tubing where it is described by the CCE. Bo and Rs are neither experimented nor known. We only know the values at $p=p_b$ and $p=p_{STC}$. In order to calculate the flash values one needs to make two assumptions: firstly, the ratio between the solution gas ration of the CCE R_{sf} and the DLE R_{sd} is constant and secondly, the difference between the formation volume factor – B_{od} - B_{of} – is proportional to the difference of the solution gas ratios R_{sd} -R_{sf}.

Dynamic behavior (viscosity) - It is evident that the viscosity is reduced by the increasing amount of gas in solution with pressure increasing. The smaller molecules act as ball bearings and facilitate the easier motion of the larger molecules. That suggests a relationship between viscosity and FVF. The temperature has especially for the viscosity a major influence. It is therefore advantageous to exclude the first order temperature depenence by including the quantities at atmospheric pressure, B_{o1} and μ_{o1}: $\ln(\mu_{o1}/\mu_o(p)=A(1-\exp(-c(B_o(p)-B_{o1})))$. Unfortunately it is not possible to find a universal function for this dependence. The constants A and c cannot be related to T_{res} or ρ_{STO}.

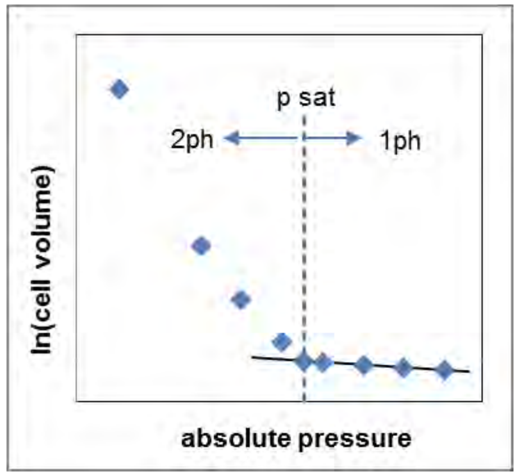
Conclusions - This paper covers the quality issues of PVT studies. Starting from sampling, sampling transportation to the laboratory experiments critical points are highlighted. Tools for checking the validity of reports are given, in particular

- properly defined Y-functions allow for the first time to compare CCE and DLE for BO and CCE and CVD of for GC,
- the FVF can be checked via gas in solution and gas composition,
- outliers in viscosity measurements are detectable via a relationship with the FVF.

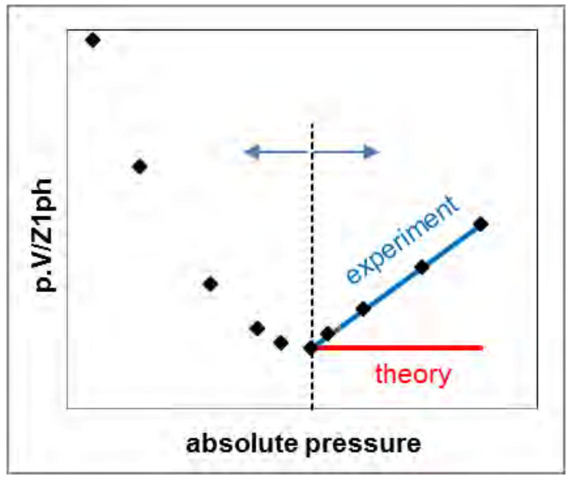
Finally, a discussion accuracy of the parameters measured listed.



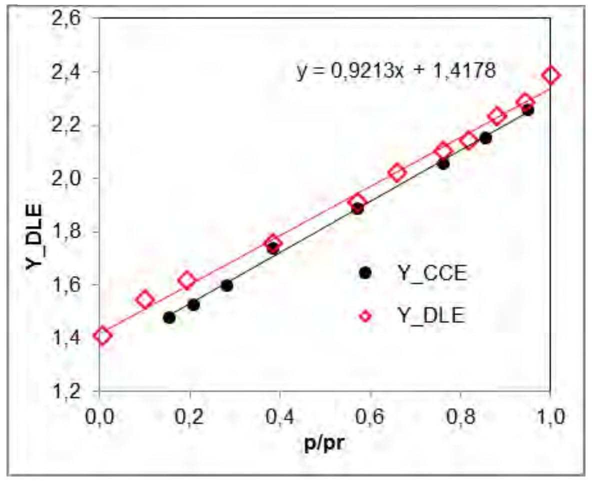
Black oil reservoir *Gas condensate reservoir*



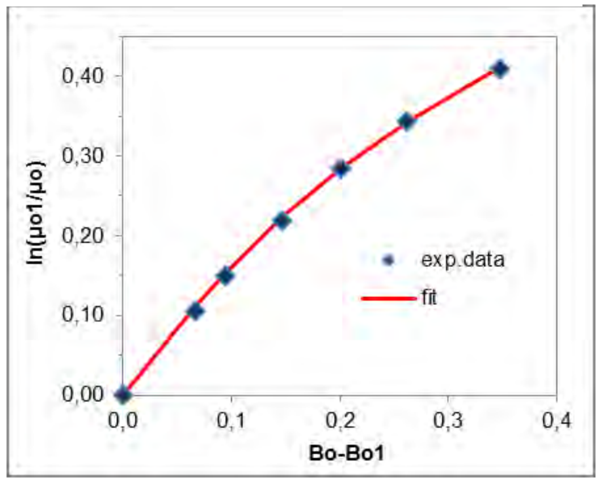
BO CCE, determination of the bubble point pressure



GC CCE determination of the dew-point pressure



Comparison of Y-function for CCE and DLE



Viscosity function versus volume increase

	pro	con
BHS	sample ready for cell, no recombination necessary	risky, small volume, composition through flash that may be inaccurate in GOR, Δp downhole inaccurate
Surface sample	easy and at any time accessible	GOR for recombination may be questionable
composition of a phase	detailed information	prior to analysis a flash may be necessary, what carrier gas was used, how many runs of the chromatograph were carried out? Grouping of higher ends needs check
GOR		changing from volume to molar units requires densities and molecular masses which are sometimes questionable for higher ends, M_{liq} very inaccurate
recombination		as above
CCE	easiest experiment accuracy depends on the type of sample, p_b determination within ±1bar	if performed too fast – inaccurate if p is always adjusted – thermodynamic equilibrium may not be reached, p too low or V too large step sizes too large
DLE		R_s: the gas readings may be inaccurate B_o: limiting factor = volume reading of the cell and V_{STO}
CVD		reaching V_{pd} after each step is difficult Well stream: heavy ends may be lost in not heated valves which results in an inaccurate mass balance

Discussion of the overall accuracies of experiments

Improved Operator Insight and Maximising Production in Offshore Fields

by Lars Anders Ruden, Emerson Process Management

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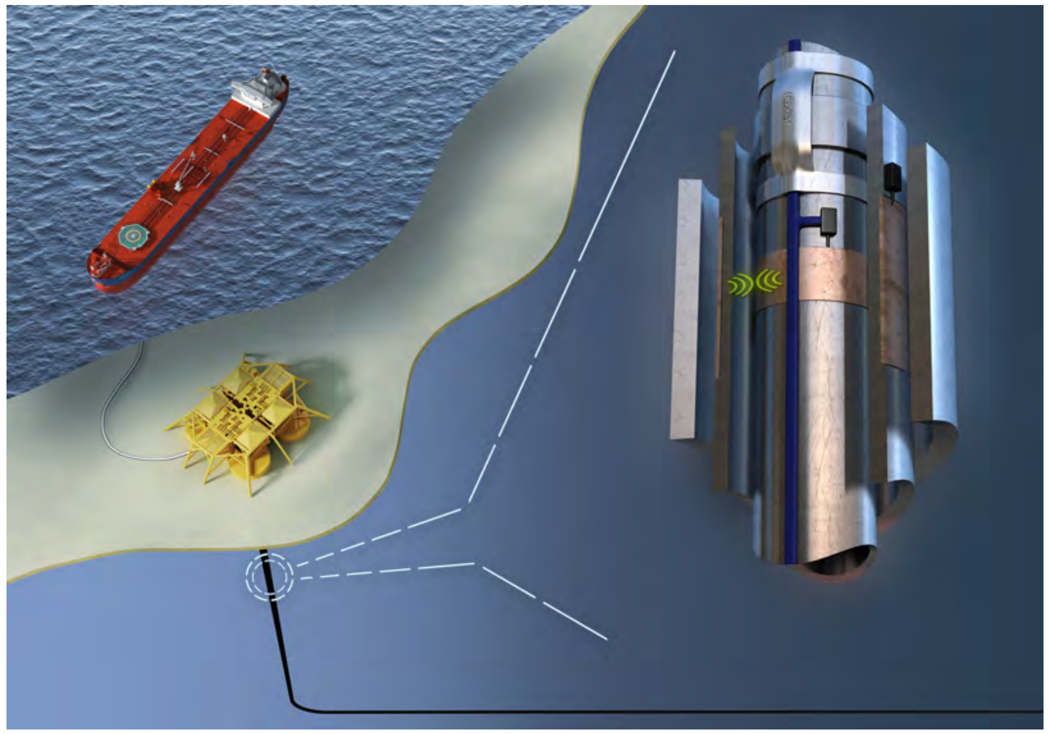
Operators today are facing significant challenges in maximising production while reducing costs – at a time of geologically complex fields, challenging operating conditions and the pressure of low oil prices.
How are my wells performing? Are there any conditions that affect production flow? How do I keep my assets working for the full life of the field? All these questions and more must be answered, with operators' ability to maximise returns dependent on understanding reservoirs and generating accurate production information.

Measuring Flow Rates – Current Challenges
One of the key elements behind optimising production today is the accurate measurement of flow rates and fluids.
Real-time flow rates for oil, gas and water mixtures generate vital information. They detect critical information relating to water/gas breakthrough, hydrate information and increased sand production and ensure that wells are operating to the limit of their capabilities.
Yet, accurate flow measurement also comes with significant challenges. Many oil & gas wells, for example, are being produced over a wider range of process conditions, more liquid and water are present - especially in high GVF and wet gas fields – and there is also a need to detect changing fluid composition and salinity.
Furthermore, with the current low oil prices, the presence of undetected formation water and water coning, and the dangers of hydrates, scale, corrosion, and - in worst case scenarios - well shutdowns can have a highly negative impact on the field's economics.

New Technology Developments
The latest technology developments in subsea and topside multiphase metering, however, are addressing these challenges.
Advanced signal processing, new field electronics (and in the case of subsea meters retrievable electronics) and electrode geometry are today providing more accurate characterizations of flow.
The field electronics system behind the Roxar Multiphase Meter, for example, allows for capacitance and conductance measurements to be combined in one unit and a Field Replaceable Insert Venturi improves accuracy and stability as well as removing uncertainties in sizing meters based on uncertain production forecasts.
The rise in wet gas fields with fast changing fluid compositions and increased salinity has also led to new technological developments that form the basis of the latest Roxar subsea Wetgas Meter.
The meter in question improves measurement uncertainty and salinity measurement as well as extends the operating range for wet gas meters. Let's take a look



The Roxar Downhole Wireless PT Sensor System monitors annulus B pressure and temperature wirelessly and continuously online for the life of the well