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Gas Condensate Well Test Analysis Using a Single-Phase Analogy

Shaosong Xu and W. John Lee, Texas A&M U.

Abstract

This paper shows that a simple, single-phase analogy using a standard dry gas pseudopressure transformation in interpreting transient buildup pressure data from a gas condensate well gives a good estimation of permeability. Under certain conditions, this method gives good estimates of damage skin, too. These results are not affected by average reservoir pressure.

We used a commercial fluid PVT package and an EOS-based compositional simulator to characterize the phase behavior of retrograde gases during reservoir depletion, to compare gas and condensate PVT properties *in situ* and at lab conditions, and to model a vertical well under varying conditions. Then we analyzed the simulated buildup transient pressure by using a single-phase analogy incorporating a radially composite model and compared the results with reservoir simulator inputs and outputs.

The numerical experiments using three actual fluid samples show that, during reservoir depletion, the vapor properties *in situ* are a function of pressure only, and correlate very well with z factor, gas molar density and viscosity obtained in lab constant composition expansion (CCE). The condensate PVT properties *in situ* depend on pressure, production mode and reservoir properties. But the effects of variables other than pressure are usually small and are constrained within a certain pressure range. As a rule, the leaner the retrograde gas, the smaller the deviations. As a practical matter, the correlations between condensate oil PVT properties obtained from lab CCE and the values *in situ* are also quite acceptable.

Our reservoir simulation showed that the pressure buildup responses can be classified into two types. In the first type, the shape of the pressure derivative suggests a well in a radially composite two-zone reservoir. In the second type, the pressure derivative suggests a well in a radial three-zone reservoir.

Our interpretation of 30 simulated cases using a radially composite two-zone model shows that a single-phase analogy gives a good estimation of permeability but underestimates condensate bank size. We cannot estimate damage skin from the first type of pressure response, but the estimation from the second type is acceptable.

Introduction

Transient pressure data, production data, and well performance analysis of gas condensate wells have been topics of abundant research in the oil industry and academia. In production, well bottomhole pressure is below the dewpoint in most cases, and the resulting multiphase fluid flow involves complicated fluid phase behavior analysis under reservoir conditions. Many efforts have been made to address the analysis of transient pressure and production data from gas condensate wells.

Analytical method. O'Dell, *et al.*[1] investigated gas condensate well performance with a single gas phase analogy by using gas z factor and viscosity obtained from lab CCE. Jones *et al.*[2, 3] used a two-phase analogy to study flow rate and pressure buildup in a gas condensate well. When they used molar density or the z factor in their pseudopressure expression, they assumed that relative permeability is a function of saturation only and that it correlates with pressure by the saturation expression derived from steady-state flow. In their calculations, the fluid molar density, z factor, and viscosity are taken from lab CCE and are functions of pressure only. Raghaven *et al.*[4] analyzed several simulated and field cases by applying single-phase and two-phase analogies. Yadavalli and Jones[5] used a radially composite model to interpret transient pressure data from hydraulically fractured gas condensate wells with a single-phase analogy.

Numerical Simulation Method. One limitation of all analytical methods is in the treatment of fluid phase behavior. Because they permit only one set of PVT data and no compositional simulation at all, it is not known whether the set of PVT data really represent the fluid behavior *in situ*. Analytical models do not include non-Darcy flow and capillary number dependent relative permeability.

To overcome these limitations, Aly *et al.*[6] applied compositional simulation in transient pressure analysis after they were disappointed by a single-phase analogy that had inappropriately used retrograde gas properties generated from dry gas correlations. Bertram *et al.*[7] used an EOS-based compositional simulator to analyze field cases. Although they included the effect of non-Darcy flow and capillary-number dependent relative permeability, their presentations of pseudopressure were in terms of the standard dry gas formulation, and wellbore storage was not included in their simulation. These simplifications made interpretation non-unique.

Proposed Interpretation Procedure

Our proposed well test analysis procedure employs a single-phase analogy method. The data required for the method include the usual bottom-hole pressure-time data, rate history prior to shutin, and laboratory Constant Composition Expansion (CCE data). These CCE data usually include the relationship between fluid relative volume and pressure and gas z factor at pressures above the dew point. The steps in the procedure follow.

1. Using a PVT package from a compositional simulator, tune an equation of state to the laboratory CCE data.

2. Calculate vapor phase viscosity and z-factor as a function of pressure throughout the pressure range of the test, using the tuned equation of state.

3. Using the vapor phase z-factor and viscosity from the laboratory, calculate pseudopressure using the classical dry-gas formulation

$$p_p = 2\int_{p_b}^{p} \frac{p}{u_g z_g dp}$$

4. Using a two-zone radial composite model (Fig. 1) from well test analysis software, analyze logarithmic and semilog plots of pseudopressure data vs. the appropriate and customary time functions. In this analysis, determine preliminary estimates of permeability, damage skin, and condensate bank radius.

5. If desired for greater accuracy, adjust the estimated permeabilities, damage skin, and condensate bank radius through history matching with a simulator.

In the remainder of the paper, we will present the justification for the steps outlined for this procedure.

Development of Single-Phase Analogy

In the work reported in this paper, we investigated the PVT properties of actual retrograde gases comprehensively. By using a commercial fluid PVT package and an EOS-based compositional simulator, we characterized the phase behavior of the actual retrograde gases during reservoir depletion through numerical experiments. We then compared gas and condensate properties of the fluids *in situ* and in laboratory CCE experiments. The gas z factor and viscosity calculated from the CCE were also compared with the values found from dry gas correlations.

Pressure drawdown and buildup responses were generated in a fully penetrating verical well under different combinations of altered permeability zones, retrograde gas richness levels, producing rates and times, reservoir rock permeability curves and reservoir permeabilities.

The simulated buildup transient pressures were analyzed using a single-phase gas analogy coupled with a radially composite reservoir model. The vapor properties obtained from the laboratory CCE were used to calculate pseudopressures used in the model. We compared the interpreted results with the reservoir simulator inputs and outputs to check their validity.

Simulation set up

We began by characterizing the phase behavior of actual retrograde gases during reservoir depletion. We used a PVT package to tune the Peng-Robinson EOS (PR EOS) for three real retrograde gases, ensuring that the components in the tuned EOS consistent with initial retrograde gas compositions. Table 1 gives the key descriptions of these fluids. For simplicity, the EOS was tuned only to the lab CCE data. Fig. 2 shows the condensate richness of these fluids.

We used an AIM compositional simulator and a PR EOS to generate pressure drawdown and buildup in a single well, assuming only gas- and oil-phase flow. Irreducible water was considered immobile. Table 2 gives the cell sizes in the radial direction in our one-dimensional composite model. In all cases, we tested the grid and time step by matching single-phase simulations to analytical solutions in which the well bottomhole pressure was above the dew point.

Fig. 3 illustrates the two-phase relative permeabilities used in the simulator. Only the sensitivity to the gas relative permeability was tested.

Table 3 gives the base-case reservoir properties. We modeled the buildup responses by producing the well at a constant (volume) gas rate for a given time, followed by a shut-in period. For test analysis purposes, we applied the standard single-phase pseudopressure transformation to buildup pressure interpretation and took the values of the gas *z* factor and viscosity from the lab CCE because they correlated very well to those in the reservoir. Since the production report generally provides the total *equivalent* gas rate, and the *actual* gas rate is unknown, we used the total equivalent gas rate in our well test analysis.

Fluid Characterization

Fluid characterization is essential to reservoir description. Any error in fluid characterization will affect the subsequent reservoir description, resulting in wrong estimation of reservoir parameters. At the beginning of our work, we analyzed the pressure responses generated from the simulator by using gas PVT properties obtained from dry gas correlations and found that the interpreted results did not agree with the simulator inputs. We examined the actual fluid phase behaviors *in situ* and compared them with the corresponding PVT properties in the lab CCE.

The gas *z*-factor, viscosity, and molar density changes with pressure in the first cell (where the well is located) are presented in Figs. 4 to 6, which show that the vapor PVT properties during depletion are functions of pressure only. They correlate very well with the properties generated by the lab CCE. When the drainage area is finite and the pressure becomes low, the well is actually producing at constant bottomhole pressure, so that the gas properties are also independent of well producing conditions. Figs. 7 to 9 illustrate that these same properties of condensate are not just functions of pressure, but the effects of variables other than pressure are small enough that the correlations with pressure alone may be considered adequate.

Cell 5 (Figs. 10 to 15) yielded the same results as Cell 1.

For Fluid Samples 2 and 3, we obtained similar conclusions but the figures are not shown here.

We also compared the gas *z* factor and viscosity generated by correlations[8] with those from the CCE (Figs. 16 and 17). For fluid 1(Table 1), the correlations worked well. For fluids 2 and 3 (not shown here), the differences between gas *z* factor and viscosity generated by the correlations and from lab CCE data are large. There were more nonhydrocarbon impurities present in these two fluids than in Fluid Sample 1.

From these results, we see that the gas *z* factor, viscosity, and molar density are functions of pressure alone. This is not the case for condensates, although the deviations from a correlation with pressure are usually small. The leaner the retrograde gas, the smaller the deviations. The gas *z* factor, molar density, and viscosity *in situ* are agree well with the ones obtained from the lab CCE. As a practical matter, oil viscosity, molar density, and z factor *in situ* also correlate well with those obtained from lab CCE. Hence, if the fluid properties obtained from the lab CCE are to be used in the pseudo-pressure calculation, the pseudo-pressure for two-phase flow could be computed as

$$\int_{p_b}^{p}\left(\frac{k_{rg}\rho_g}{\mu_g}+\frac{k_{ro}\rho_o}{\mu_o}\right)dp \text{ or } \int_{p_b}^{p}\left(\frac{k_{rg}}{\mu_g z_g}+\frac{k_{ro}}{\mu_o z_o}\right)dp \,. \qquad (1)$$

In the single gas phase analogy, the pseudopressure is calculated by neglecting the second term in the integral. We do not recommend dry gas PVT correlations for retrograde gas PVT calculation, especially when the content of non-hydrocarbon impurities is high.

Buildup Pressure Characteristics

Altered permeability zone effect. In gas condensate wells, formation damage can no longer be represented as skin on the wellbore but requires a finite altered permeability zone (Fig. 1). If oil saturation in the condensate bank is assumed constant, the total skin is

$$s_t = \frac{s_m}{k_{rg}} + s_p \;, \qquad (2)$$

where s_m is mechanical skin, k_{rg} is gas relative permeability at the condensate bank, and s_p is the skin caused by condensate drop out. The appendix gives the derivation in detail.

Type I and Type II buildup pressure response. Fig. 18 shows what we call the “Type I” buildup pressure response. The pressure derivative of this response, which is caused by a small condenate bank, has two horizontal straight lines. The pressure derivative of what we call the “Type II” pressure buildup response (Fig. 19) has three horizontal straight lines that represent the responses of an altered permeability zone, the condensate bank, and the undisturbed formation. This type of pressure response appears when a condensate bank is much larger than the altered permeability zone. Fig. 20 illustrates another Type II pressure buildup response, but the pressure derivative offset between the second and third horizontal straight lines is smaller, indicating that the condensate has dropped out in the entire drainage area. Fig. 21 shows the oil saturation distribution before this pressure buildup test. Our simulation showed that the extent of a condensate bank is determined by reservoir permeability, mechanical skin, fluid richness, well rate, the difference between initial pressure and dewpoint pressure, and production time.

Pressure buildup analysis

Well test analysis model. We used a radially composite model with two zones (Fig.1) to analyze the buildup pressure transients. Pressure drawdown and buildup responses were generated in a fully penetrating vertical well under different combinations of altered permeability zone, retrograde gas richness levels, producing rates and time, reservoir rock relative permeability curves and reservoir permeability.

The simulated buildup transient pressure was analyzed by using a single gas analogy in a radially composite model. We used the vapor gas properties obtained from the lab CCE in pseudopressure calculations. We compared the interpreted results with the reservoir simulator inputs and outputs to check their validity.

For the Type I pressure response, where the altered permeability zone cannot be distinguished from the condensate bank, the interpreted inner zone permeability is the effective permeability to gas in the altered permeability zone. The interpreted inner zone radius indicates the condensate bank front and the outer zone is the undisturbed reservoir. The computed skin is zero because the well fully penetrates the formation.

In the Type II pressure response, we analyzed the data corresponding to the second and third horizontal straight lines of the pressure derivative. If the reservoir pressure was higher than the dew point pressure, the interpreted outer zone permeability was the original reservoir permeability, the interpreted inner zone radius indicated the extent of the condensate bank, and the calculated skin was the mechanical skin. If the reservoir average pressure was below dew point pressure, the computed permeabilities were the effective permeabilities to gas in the first and second condensate banks and the calculated skin was the mechanical skin.

Interpreted Results. After we characterized three actual fluids, we interpreted about 30 simulated cases by using the well test model mentioned above and checked the calculated results with the simulator input and output. Our results demonstrated that good estimation of permeability can be obtained. The mechanical skin was about one unit below the real one in the worst case, and the computed condensate bank radius was one-half the accepted value if the reservoir average pressure fell below the dewpoint pressure. Introducing a pseudotime transform did not improve the results.

The interpreted condensate bank radius is smaller than that of the simulator because the condensate front is not sharp. Fig. 21 shows that oil saturation decreases smoothly along the condensate bank. Hence, the effective permeability to gas increases gradually. Our radial composite model shows a sharp permeability change interface.

Although our single-phase analogy was quite successful in buildup pressure analysis, it failed in well rate decline analysis by typecurve matching. We tried several simulated cases, but we could not achieve an adequate match.

Conclusions

1. During reservoir depletion the vapor *z* factor, molar density, and viscosity are functions of pressure only.

2. During reservoir depletion the condensate *z* factor, molar density, and viscosity are not functions of pressure alone, although the deviations from a correlation with pressure alone are usually small and constrained with a certain pressure range. The leaner the retrograde gas, the smaller the deviations.

3. Using dry gas correlations to generate gas *z* factor and viscosity is not recommended, especially when the content of non-hydrocarbon impurities is high.

4. The vapor viscosity, *z* factor, and molar density *in situ* agree well with the values obtained from the lab CCE. As a practical matter, the oil viscosity, *z* factor, and molar density also well correlate well with the ones obtained from lab CCE The pseudopressure for two-phase flow could be calculated from Eq. 1 if the fluid properties obtained from the lab CCE are to be used in its calculation. In the single-phase analogy, the pseudopressure is computed by neglecting the second term in the integral.

5. The two-zone radially composite model is applicable to interpretation of buildup transient pressure although the condensate bank distance is underestimated and we cannot obtain damage skin from the "Type I" pressure response.

Nomenclature

k = permeability, md
k_s = altered zone permeability
k_{rg} = gas relative permeability
k_{ro} = oil relative permeability
p_p = pseudopressure, psia^2/cp
p = reservoir pressure, psia
p_{av} = reservoir average pressure, psia
p_{dew} = dewpoint pressure, psia
q = well rate, MMscf
r = radial distance, ft
r_w = wellbore radius, ft
r_p = condensate bank radius, ft
r_s = altered permeability zone radius, ft
s_t = total skin, estimated from Horner analysis
s_{2p} = skin caused by condensate drop out
s'_p = partial skin cased by condensate drop out
s_{p+m} = skin caused by condensate drop out and formation damage in altered permeability zone
z_g = gas deviation factor
z_o = oil deviation factor
μ_o = oil viscosity, cp
μ_g = gas viscosity, cp
ρ_g = gas molar density, lbm mol/ft^3
ρ_o = oil molar density, lbm mol/ft^3

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8. Lee, John and Wattenbarger, R.A.: *Gas Reservoir Engineering*, SPE Textbook Series, Vol. 5, SPE, Richardson, TX (1996).

Appendix

Condensate drop out effect on skin factor

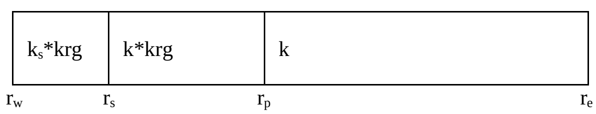

Fig. 22 - Reservoir model

Consider the reservoir model shown in Fig. 22 if the condensate bank radius, r_p > altered permeability zone radius r_s, and oil saturation is constant in the condensate bank under steady state flow, then

$$s'_p = (\frac{k}{k*k_{rg}} - 1)\ln\frac{r_p}{r_s} = \frac{1}{k_{rg}}(1-k_{rg})\ln\frac{r_p}{r_s} \qquad \text{(A-1)}$$

$$s_{p+m} = (\frac{k}{k*k_{rg}} - 1)\ln(\frac{r_s}{r_w}) \qquad \text{(A-2)}$$

Eq. A-2 can be modified as

$$s_{p+m} = \frac{s_m}{k_{rg}} + \frac{1}{k_{rg}}(1-k_{rg})\ln\frac{r_s}{r_w}\ , \qquad \text{(A-3)}$$

where $s_m = (\frac{k}{k_s} - 1)\ln\frac{r_s}{r_w}$. (A-4)

If the skin caused by condensate drop out is defined as

$$s_p = (\frac{k}{k*k_{rg}} - 1)\ln\frac{r_p}{r_w} = \frac{1}{k_{rg}}(1-k_{rg})\ln\frac{r_p}{r_w}\ , \qquad \text{(A-5)}$$

the total skin is

$$s_t = s_{p+m} + s'_p\ . \qquad \text{(A-6)}$$

Substitute Eqs. A-1 and A-3 into A-6, and using Eq. A-5, we obtain

$$s_t = \frac{s_m}{k_{rg}} + s_p\,. \qquad \text{(A-7)}$$

Eq. A-7 shows that the total skin factor for single-gas flow will be much larger than the sum of s_m and s_p if r_p is less than or equal to the altered zone permeability radius r_s. Eq. A-7 can also be obtained by using the same arguments.

Table 1 - Retrograde gas characteristics

Fluids	1	2	3
Dew point, psia	3524.5	6015.2	3368.3
Maximum So in CCE	0.22	0.34	0.10
Pseudo-components	9	11	10
Reservoir temperature, ^oF	200	256	240

Table 2 - Cell sizes in radial direction

Grid number, 29 Inner most grid radius, ft, 0.25 Cell size, ft, 0.40, 0.7268, 1.198, 1.976, 3.257, 5.37, 7.0, 9.0 11.0, 14.60, 20.07, 37.70, 55.42, 70.0, 70.0, 70.0 70.0, 70.0, 70.0, 70.0, 70.0, 70.0, 70.0, 100.0,100.0 100.0, 100.0, 100.0, 100.0

Table 3 - Reservoir properties in base case

parameter	Value
ϕ	0.20
h, ft	30
r_s, ft	2.57
r_e, ft	1368.0
k_s, md	2
k, md	5
s	3.5
S_{wirr}, fraction	0.16
q, MMscf/D	4.0
p_i, psia	3900

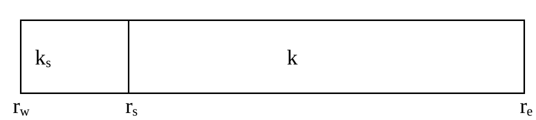

Fig. 1 - Well test analysis model

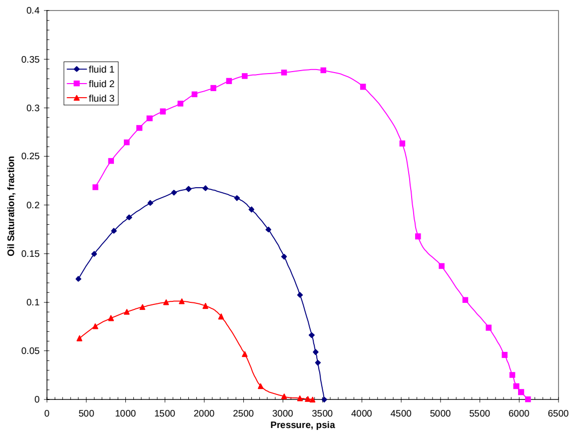

Fig. 2 - Oil saturation in lab CCE

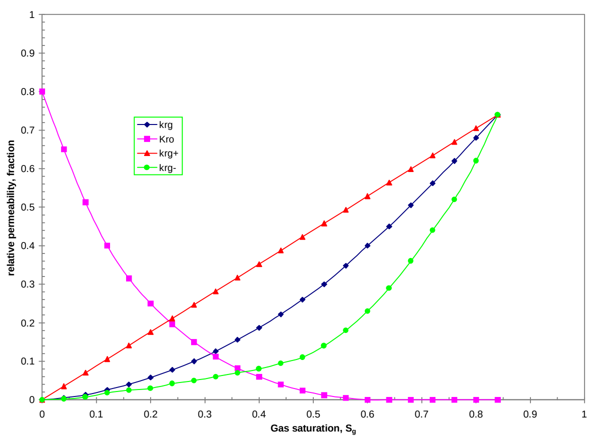

Fig. 3 - Relative permeability curves

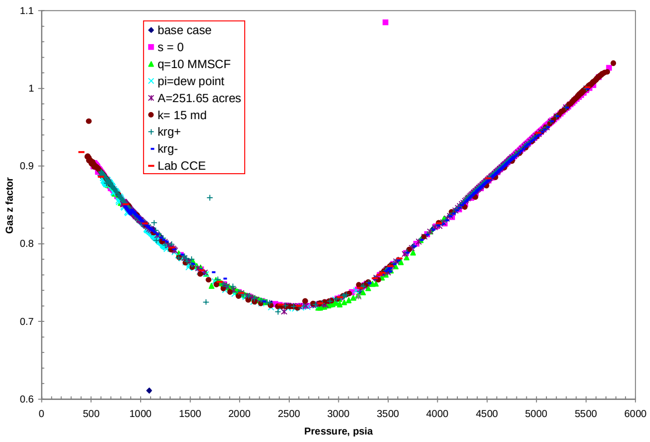

Fig. 4 - Gas *z* factor in Cell 1, Fluid 1

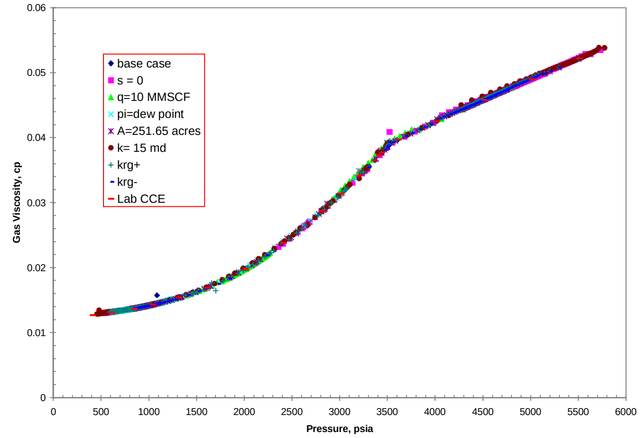

Fig. 5 - Gas viscosity in Cell 1, Fluid 1

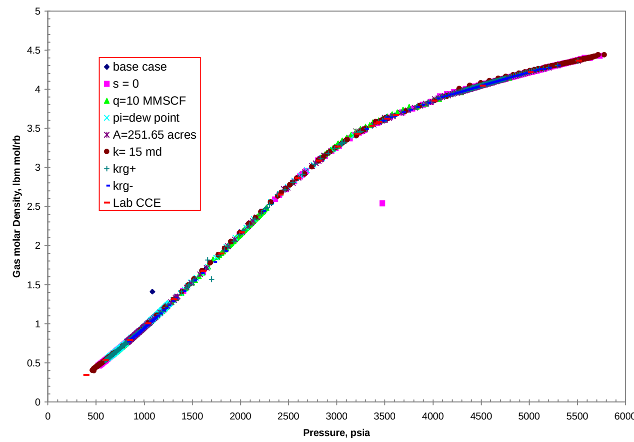

Fig. 6 - Gas molar density in Cell 1, Fluid 1

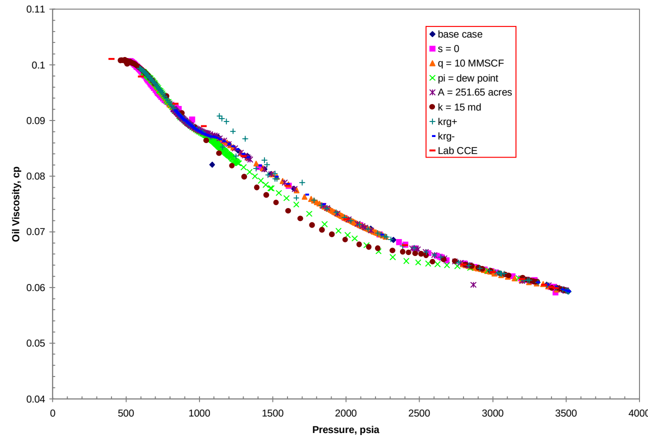

Fig. 7 - Oil viscosity in Cell 1, Fluid 1

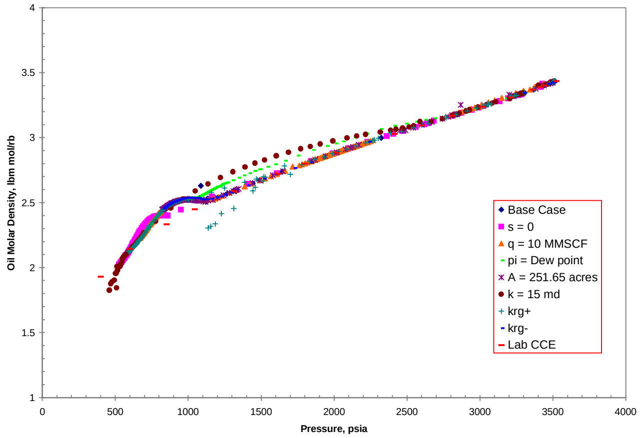

Fig. 8 - Oil molar density in Cell 1, Fluid 1

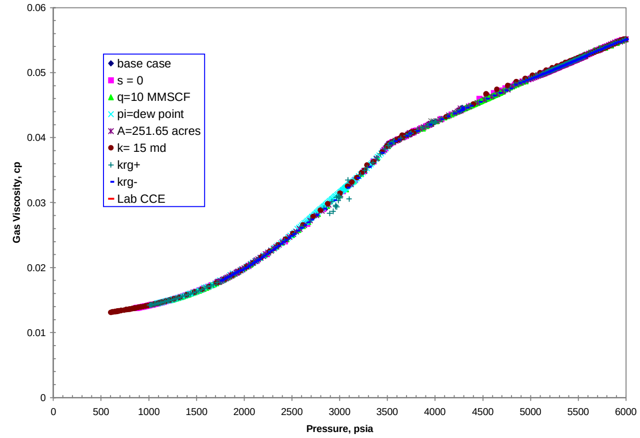

Fig. 11 - Gas viscosity in Cell 5, Fluid 1

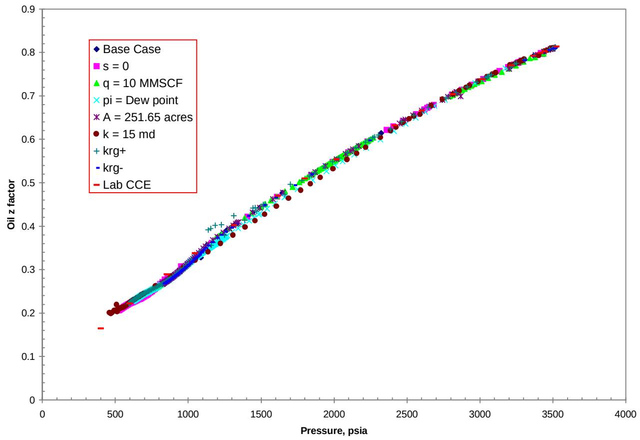

Fig. 9 - Oil *z* factor in Cell 1, Fluid 1

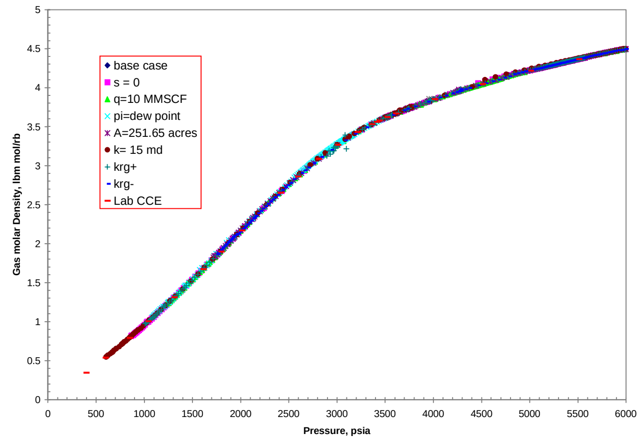

Fig. 12 - Gas molar density in Cell 5, Fluid 1

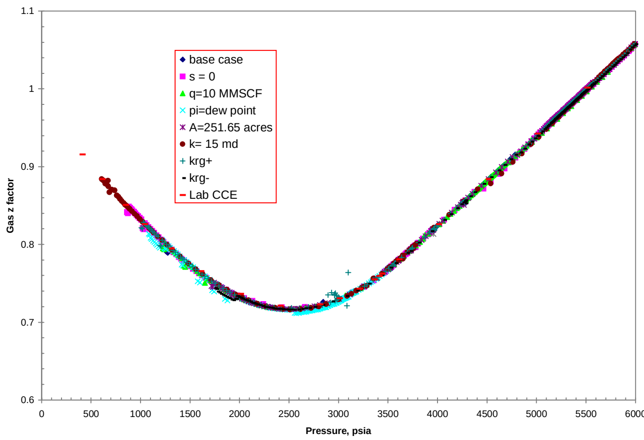

Fig. 10 - Gas z factor in Cell 5, Fluid 1

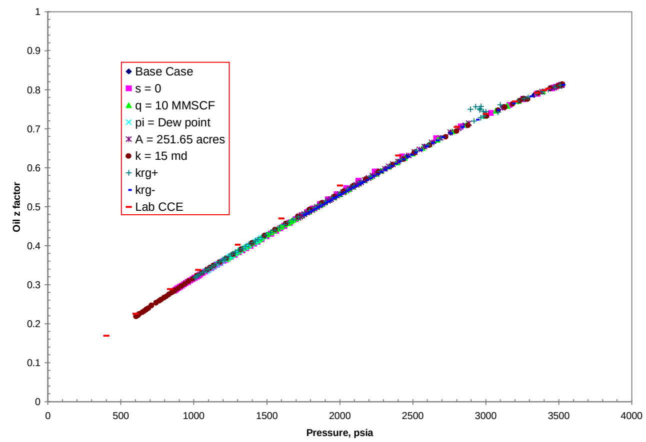

Fig. 13 - Oil *z* factor in Cell 5, Fluid 1

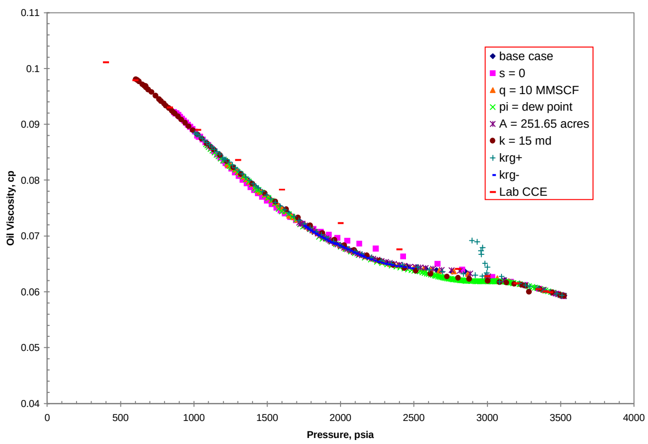

Fig. 14 - Oil viscosity in Cell 5, Fluid 1

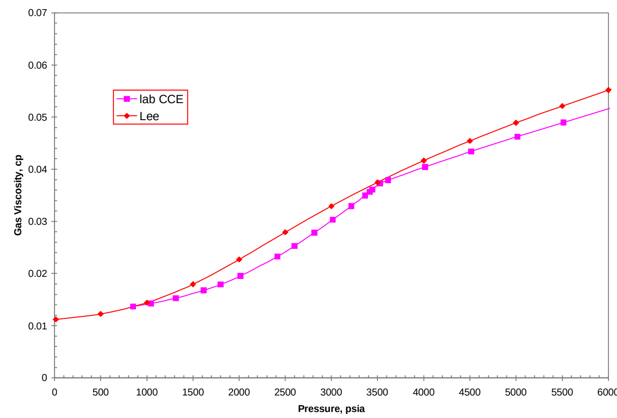

Fig. 17 - Comparison of gas viscosities, Fluid 1

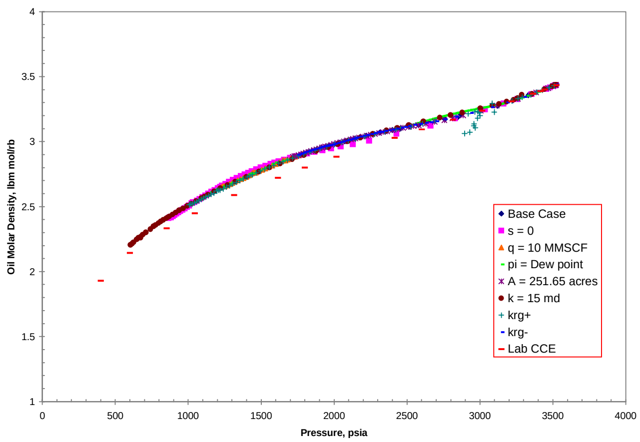

Fig. 15 - Oil molar density in Cell 5,Fluid 1

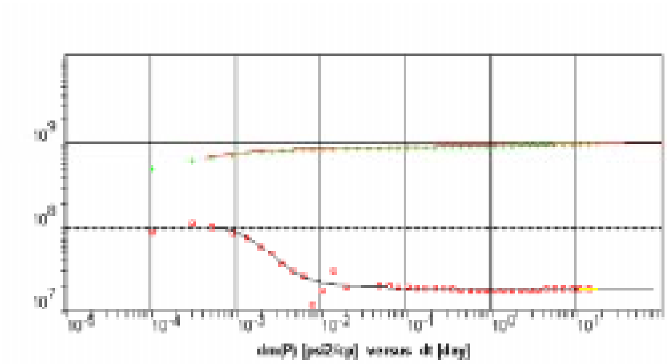

Fig. 18 - Type I buildup pressure response and its analysis, Fluid 1

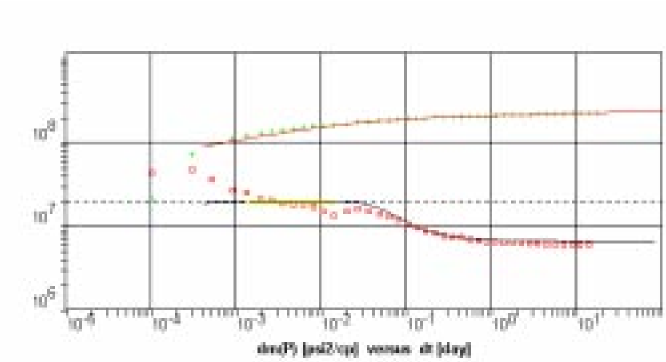

Fig. 19 - Type II buildup pressure response and its analysis, fluid 1

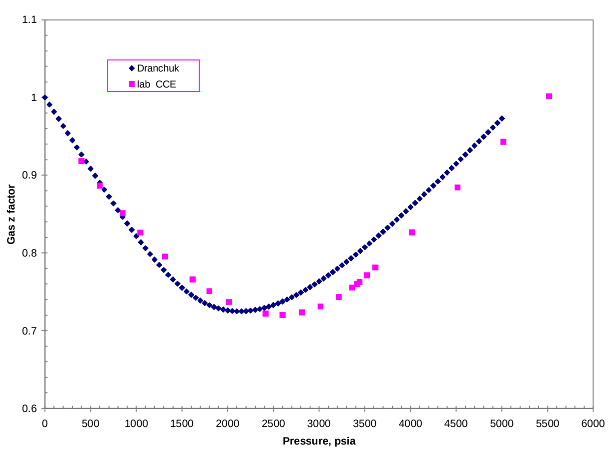

Fig. 16 - Comparison of gas z factors, fluid 1

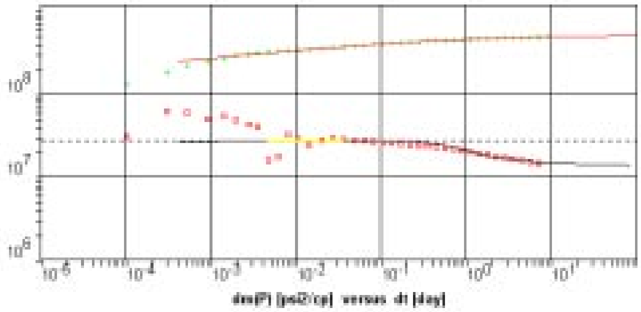

Fig. 20 - Buildup pressure response and analysis when p_{av} < p_{dew}, fluid 1

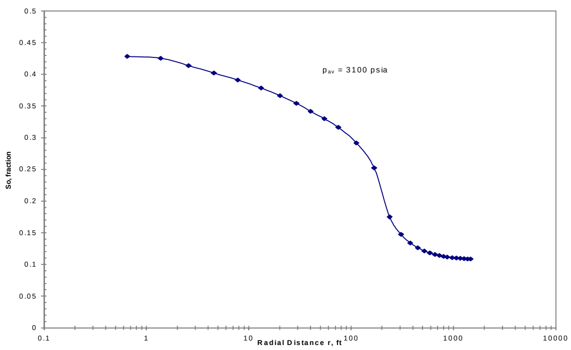

Fig. 21 - Oil saturation before pressure buildup shown in Fig. 20, Fluid 1